2002 WHOLESALE POWER RATE SCHEDULES (WP-02)

2002 GENERAL RATE SCHEDULE PROVISIONS REVISED FY 2003

FIRM POWER PRODUCTS AND SERVICES RATE (FPS-96R)

GENERAL TRANSFER AGREEMENT DELIVERY CHARGE

Revised May 2004

BONNEVILLE
POWER ADMINISTRATION

United States Department of Energy
Bonneville Power Administration
905 NE. 11^{th} Avenue
Portland, OR 97232

Bonneville Power Administration's (BPA) 2002 Wholesale Power Rate Schedules and General Rate Schedule Provisions (GRSPs), effective October 1, 2001, and contained herein, were approved on a final basis by the Federal Energy Regulatory Commission (FERC) on July 21, 2003. *U.S. Dep't of Energy – Bonneville Power Admin*., 104 FERC ¶ 61,093 (2003).

Except as noted below, these 2002 rate schedules and provisions supersede BPA's 1996 Wholesale Power Rate Schedules and General Rate Schedule Provisions.

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The Firm Power Products and Services (FPS-96R) rate adjustment was approved on a final basis, effective April 16, 2001, by FERC on April 16, 2001. *U.S. Dep't of Energy – Bonneville Power Admin*., 95 FERC ¶ 61,082 (2001).

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The General Transfer Agreement (GTA) Delivery Charge was approved on a final basis, effective October 1, 2003, by FERC on September 23, 2003. *U.S. Dep't of Energy – Bonneville Power Admin*., 104 FERC ¶ 62,207 (2003).

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The Safety-Net and Financial-Based Cost Recovery Adjustment Clauses (SN CRAC and FB CRAC), and the Dividend Distribution Clause were approved on an interim basis effective October 1, 2003. *U.S. Dep't of Energy – Bonneville Power Admin*., 105 FERC ¶ 61,006 (2003).

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These rate schedules and General Rate Schedule Provisions include all errata corrections as of the date of publication.

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ACRONYM LIST

AAMTA	Augmentation Amount Actual
AAMTF	Augmentation Amount Forecast
AANR	Audited Accumulated Net Revenues
ACTUALLBCREVREQ	Actual Load-Based Cost Recovery Adjustment Clause Revenue Required
ACTUALLBCREVREQ(NS)	Actual Load-Based Cost Recovery Adjustment Clause Revenue Required (non-Slice)
ACTUALLBCREVREQ(S)	Actual Load-Based Cost Recovery Adjustment Clause Revenue Required (Slice)
ADJUST(NS)	Adjustment to a Purchaser's Non-Slice Monthly Bill
ADJUST(S)	Adjustment to a Purchaser's Slice Monthly Bill
AGC	Automatic Generation Control
aMW	Average Megawatt
ANR	Accumulated Net Revenues
APP	Augmentation Pre-Purchase
ASC	Average System Cost
BPA	Bonneville Power Administration
BUYDOWN	Cost of Load Buydown
C/M	Consumers/Mile of Line for Low Density Discount
C&R Discount	Conservation and Renewables Discount
C&R(NS)	Conservation and Renewables Discount–Non-Slice
C&R(S)	Conservation and Renewables Discount–Slice
CalPX	California Power Exchange
COB	California-Oregon Border
CRAC	Cost Recovery Adjustment Clause
CSP	Customer System Peak
CUSTREV(NS)	Customer Revenue with LB CRAC–Non-Slice
CUSTREV(S)	Customer Revenue with LB CRAC–Slice
CY	Calendar Year (Jan-Dec)
DDC	Dividend Distribution Clause
DIURNALACA	Diurnal Augmentation Cost Actual
DIURNALACF	Diurnal Augmentation Cost Forecasted
DJ	Dow Jones
DSIs	Direct Service Industrial Customers
Energy Northwest	Formerly Washington Public Power Supply System (Nuclear)
EPP	Environmentally Preferred Power
FB CRAC	Financial-Based Cost Recovery Adjustment Clause
FCCF	Fish Cost Contingency Fund
FCRPS	Federal Columbia River Power System
FERC	Federal Energy Regulatory Commission
FPS	Firm Power Products and Services (rate)
FY	Fiscal Year (Oct-Sep)
GEP	Green Energy Premium

GRSPs	General Rate Schedule Provisions
GSP	Generation System Peak
GTA	General Transfer Agreement
HLH	Heavy Load Hour
IOUs	Investor-Owned Utilities
IP	Industrial Firm Power (rate)
IPTAC	Industrial Firm Power Targeted Adjustment Charge
ISO	Independent System Operator
K/I	Kilowatthour/Investment Ratio
kV	Kilovolt (1000 volts)
kW	Kilowatt (1000 watts)
kWh	Kilowatthour
LB CRAC	Load-Based Cost Recovery Adjustment Clause
LB CRAC%	Percent applied to sales revenue for loads subject to the LB CRAC
LBCREV(NS)	LB CRAC Revenues (Non-Slice) Received by BPA
LBCREV(S)	LB CRAC Revenues (Slice) Received by BPA
LDD	Low Density Discount
LDD(NS)	Low Density Discount Non-Slice
LDD(S)	Low Density Discount Slice
LLH	Light Load Hour
LME	London Metal Exchange
LOAD(NS)	Non-Slice Load Subject to LB CRAC
LOAD(S)	Slice Load Subject to LB CRAC
MARRA	Monthly Augmentation Resale Revenues Actual
MARRF	Monthly Augmentation Resale Revenues Forecasted
May Proposal	May 2000 Final Power Rate Proposal for the WP-02 Rate Case
Mid-C	Mid-Columbia
MIMA	Market Index Monthly Adjustment
MSC	Monthly System Capability
MW	Megawatt (1 million watts)
MWh	Megawatthour
NACA	Net Augmentation Cost Actual
NACDIFF	Net Augmentation Cost Difference
NACF	Net Augmentation Cost Forecasted
NCIS	Net Cost of the Inventory Solution
NERC	North American Electric Reliability Council
NF	Nonfirm Energy (rate)
NLSL	New Large Single Load
NOB	Nevada-Oregon Border
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NPV	Net Present Value
NR	New Resource Firm Power (rate)
NSL(A)	Actual Non-Slice Load
NSL(F)	Forecasted Non-Slice Load

NT	Network Integration Transmission
NWPP	Northwest Power Pool
NYMEX	New York Mercantile Exchange
OC	Option Costs
PBL	Power Business Line
PF	Priority Firm Power (rate)
PNW	Pacific Northwest
POD	Point of Delivery
POI	Point of Integration/Point of Interconnection
POM	Point of Metering
PRICE	Price for Augmentation Amounts Not Pre-Purchased
Project Act	Bonneville Project Act
RATE(NS)	Non-Slice Rates Without LB CRAC
RATE(S)	Slice Rates Without LB CRAC
REP	Residential Exchange Program
REP Settlement	Investor-Owned Utilities Residential Exchange Program Settlement
REVDIFF(NS)	Revenue Difference Non-Slice
REVDIFF(S)	Revenue Difference Slice
REVRATE(NS)	Adjusted Non-Slice Rates
REVRATE(S)	Adjusted Slice Rate
REVw/LBC(NS)	Actual Non-Slice Revenues
REVw/LBC(S)	Actual Slice Revenues
REVw/oLBC(NS)	Baseline Non-Slice Revenues
REVw/oLBC(S)	Baseline Slice Revenues
RL	Residential Load (rate)
ROD	Record of Decision
SALESMAYAUGA	Actual Sales of Existing Augmentation Quantity
SALESMAYAUGF	Forecasted Sales of Existing Augmentation Quantity
SALESNEWAUGA	Actual Sales of New Augmentation Quantity
SALESNEWAUGF	Forecasted Sales of New Augmentation Quantity
SCRA	Supplemental Contingency Reserve Adjustment
Slice	Slice of the System product
SN CRAC	Safety-Net Cost Recovery Adjustment Clause
SNR	Safety-Net Cost Recovery Adjustment Clause Rebate
SUMY	Stepped-Up Multiyear
TAC	Targeted Adjustment Charge
TARRA	Total Augmentation Resale Revenue Actual
TARRF	Total Augmentation Resale Revenue Forecasted
TAUGCA	Total Augmentation Cost Actual
TAUGCF	Total Augmentation Cost Forecasted
TBL	Transmission Business Line (BPA)
TCAPPA	Total Cost of Augmentation Pre-Purchases Actual
TCAPPF	Total Cost of Augmentation Pre-Purchases Forecasted
TLA	Transmission Loss Adjustment

TPL	Total Plant Load
TPP	Treasury Payment Probability
Transmission System Act	Federal Columbia River Transmission System Act
TREVw/LBC(NS)	Total Revenues for Non-Slice With LB CRAC
TREVw/LBC(S)	Total Revenues for Slice with LB CRAC
TREVw/oLBC(NS)	Total Non-Slice Revenues Without LB CRAC
TREVw/oLBC(S)	Total Slice Revenues without LB CRAC
TRL	Total Retail Load
TTREVw/LBC	Total Revenues with LB CRAC
TTREVw/oLBC	Total Revenues without LB CRAC
UDC	Utility Distribution Company
WSCC	Western Systems Coordinating Council
WSPP	Western Systems Power Pool

2002 WHOLESALE POWER RATE SCHEDULES (WP-02)

Note: The 2002 Power Rate Schedules reference the 2002 General Rate Schedule Provisions (GRSPs) starting on Page 75. No changes have been made to these rate schedules, but three of the GRSPs have been revised: Financial-Based Cost Recovery Adjustment Clause (FB CRAC), Safety-Net Cost Recovery Adjustment Clause (SN CRAC), and the Dividend Distribution Clause (DDC).

BONNEVILLE
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SCHEDULE PF-02
PRIORITY FIRM POWER RATE

SECTION I. AVAILABILITY

This schedule is available for the contract purchase of Firm Power to be used within the Pacific Northwest (PNW). Priority Firm Power may be purchased by public bodies, cooperatives, and Federal agencies for resale to ultimate consumers; for direct consumption; and for Construction, Test and Start-Up, and Station Service. Rates in this schedule are in effect beginning October 1, 2001, and are available for purchase under requirements Firm Power sales contracts for a three- or five-year period. The Slice Product is only available for public bodies and cooperatives. Utilities participating in the Residential Exchange Program under section 5(c) of the Northwest Power Act may purchase Priority Firm Power pursuant to the Residential Exchange Program. Utilities participating in settlement of the Residential Exchange Program may purchase Priority Firm Power pursuant to their Subscription settlement agreement. Rates under contracts that contain charges that escalate based on BPA's Priority Firm Power rates shall be based on the five-year rates listed in this rate schedule in addition to applicable transmission charges.

Sales under the PF Exchange Subscription rate will be delivered in equal hourly amounts over the rate period. The consumer bills of participating investor-owned utilities (IOU) should designate "Benefits of the Federal Columbia River Power System (FCRPS)" to describe the amount of benefits each consumer receives. Only the block product is available under this rate schedule.

This rate schedule supersedes the PF-96 rate schedule, which went into effect October 1, 1996. Sales under the PF-02 rate schedule are subject to BPA's 2002 General Rate Schedule Provisions (2002 GRSPs). Products available under this rate schedule are defined in the 2002 GRSPs. For sales under this rate schedule, bills shall be rendered and payments due pursuant to BPA's 2002 GRSPs and billing process.

For ease of reference BPA uses the term PF rate, and PF Preference rate interchangeably. For the PF Exchange rate, BPA clarifies which rate it is discussing by using either PF Exchange Program rate or PF Exchange Subscription rate.

SECTION II. RATES TABLES

The rates in this section apply to PF products. The PF Exchange Program rates and the PF Exchange Subscription rates are shown in Section III.

A. DEMAND RATE

1. Monthly Demand Rate for FY 2002 through FY 2006

1.1 Applicability

These rates apply to customers purchasing Firm Power for three or five years. These rates are also used to implement the Pre-Subscription Contracts.

1.2 Rate Table

Applicable Months	***Rate***
January	$2.16/kW-mo
February	$2.03/kW-mo
March	$1.82/kW-mo
April	$1.45/kW-mo
May	$1.43/kW-mo
June	$1.79/kW-mo
July	$2.31/kW-mo
August	$2.31/kW-mo
September	$2.31/kW-mo
October	$1.76/kW-mo
November	$2.31/kW-mo
December	$2.31/kW-mo

B. ENERGY RATE

1. Monthly Energy Rates for FY 2002 through FY 2004

1.1 Applicability

These rates apply to customers purchasing power in the first three years of the rate period.

1.2 Rate Table

Applicable Months	***HLH Rate***	***LLH Rate***
January	19.52 mills/kWh	13.54 mills/kWh
February	17.98 mills/kWh	12.54 mills/kWh
March	16.23 mills/kWh	10.82 mills/kWh
April	12.58 mills/kWh	8.22 mills/kWh
May	12.53 mills/kWh	6.65 mills/kWh
June	15.85 mills/kWh	8.20 mills/kWh
July	21.03 mills/kWh	14.09 mills/kWh
August	31.42 mills/kWh	17.33 mills/kWh
September	22.34 mills/kWh	18.19 mills/kWh
October	15.67 mills/kWh	11.16 mills/kWh
November	21.40 mills/kWh	17.11 mills/kWh
December	22.05 mills/kWh	16.77 mills/kWh

2. Monthly Energy Rates for FY 2005 through FY 2006

2.1 Applicability

These rates apply to purchases during the last two years of the rate period for customers purchasing for all five years of the rate period.

2.2 Rate Table

Applicable Months	*HLH Rate*	*LLH Rate*
January	21.02 mills/kWh	15.04 mills/kWh
February	19.48 mills/kWh	14.04 mills/kWh
March	17.73 mills/kWh	12.32 mills/kWh
April	14.08 mills/kWh	9.72 mills/kWh
May	14.03 mills/kWh	8.15 mills/kWh
June	17.35 mills/kWh	9.70 mills/kWh
July	22.53 mills/kWh	15.59 mills/kWh
August	32.92 mills/kWh	18.83 mills/kWh
September	23.84 mills/kWh	19.69 mills/kWh
October	17.17 mills/kWh	12.66 mills/kWh
November	22.90 mills/kWh	18.61 mills/kWh
December	23.55 mills/kWh	18.27 mills/kWh

3. Monthly Energy Rates for FY 2002 through FY 2006

3.1 Applicability

These rates are used to implement the Pre-Subscription Contracts. These rates are also available to customers purchasing for all five years of the rate period under this rate table.

3.2 Rate Table

Applicable Months	*HLH Rate*	*LLH Rate*
January	20.12 mills/kWh	14.14 mills/kWh
February	18.58 mills/kWh	13.14 mills/kWh
March	16.83 mills/kWh	11.42 mills/kWh
April	13.18 mills/kWh	8.82 mills/kWh
May	13.13 mills/kWh	7.25 mills/kWh
June	16.45 mills/kWh	8.80 mills/kWh
July	21.63 mills/kWh	14.69 mills/kWh
August	32.02 mills/kWh	17.93 mills/kWh
September	22.94 mills/kWh	18.79 mills/kWh
October	16.27 mills/kWh	11.76 mills/kWh
November	22.00 mills/kWh	17.71 mills/kWh
December	22.65 mills/kWh	17.37 mills/kWh

C. LOAD VARIANCE RATE

The Load Variance rate for FY 2002 through FY 2006 applies to all customers purchasing power under this rate schedule unless specifically excluded in Section IV below. The rate for Load Variance is 0.8 mills/kWh.

D. SLICE RATE

1. Applicability

This rate is available to customers purchasing the Slice Product for the first five years of their Slice contract. This rate will remain constant during the five years of the rate period.

2. Rate

The monthly rate for the Slice Product is $1,419,430 per 1 percent of the Slice System.

SECTION III. PF EXCHANGE RATE TABLES

The rates in this section apply to sales under the Residential Exchange Program and the Subscription settlements of the Residential Exchange Program.

A. DEMAND RATE

1. Monthly Demand Rate for FY 2002 through FY 2006

1.1 Applicability

These rates apply to customers purchasing power for all five years of the rate period under the Residential Exchange Program and to customers purchasing power for all five years of the rate period under Subscription settlements of the Residential Exchange Program.

1.2 Rate Table

Applicable Months	***Rate***
January	$2.16/kW-mo
February	$2.03/kW-mo
March	$1.82/kW-mo
April	$1.45/kW-mo
May	$1.43/kW-mo
June	$1.79/kW-mo
July	$2.31/kW-mo
August	$2.31/kW-mo
September	$2.31/kW-mo
October	$1.76/kW-mo
November	$2.31/kW-mo
December	$2.31/kW-mo

B. ENERGY RATE

1. PF Exchange Program Energy Rates for FY 2002 through FY 2006

1.1 Applicability

These rates apply to customers purchasing power for all five years of the rate period under the Residential Exchange Program.

1.2 Rate Table

Applicable Months	***Energy Rate***
January	29.22 mills/kWh
February	27.18 mills/kWh
March	24.53 mills/kWh
April	19.47 mills/kWh
May	18.30 mills/kWh
June	22.84 mills/kWh
July	31.34 mills/kWh
August	44.27 mills/kWh
September	35.08 mills/kWh
October	24.18 mills/kWh
November	33.45 mills/kWh
December	33.95 mills/kWh

2. PF Exchange Subscription Energy Rates for FY 2002 through FY 2006

2.1 Applicability

These rates apply to eligible customers purchasing power under Subscription settlements of the Residential Exchange Program for all five years of the rate period.

2.2 Rate Table

Applicable Months	*HLH Rate*	*LLH Rate*
January	20.12 mills/kWh	14.14 mills/kWh
February	18.58 mills/kWh	13.14 mills/kWh
March	16.83 mills/kWh	11.42 mills/kWh
April	13.18 mills/kWh	8.82 mills/kWh
May	13.13 mills/kWh	7.25 mills/kWh
June	16.45 mills/kWh	8.80 mills/kWh
July	21.63 mills/kWh	14.69 mills/kWh
August	32.02 mills/kWh	17.93 mills/kWh
September	22.94 mills/kWh	18.79 mills/kWh
October	16.27 mills/kWh	11.76 mills/kWh
November	22.00 mills/kWh	17.71 mills/kWh
December	22.65 mills/kWh	17.37 mills/kWh

C. LOAD VARIANCE RATE

The Load Variance rate for FY 2002 through FY 2006 applies to all customers purchasing power under this rate schedule unless specifically excluded in Section IV.H below.
The rate for Load Variance is 0.8 mills/kWh.

SECTION IV. PRODUCT LIST

The rates described above apply to the following:

Section IV.A. Full Service Product

Section IV.B. Actual Partial Service Product – Simple

Section IV.C. Actual Partial Service Product – Complex

Section IV.D. Block Product

Section IV.E. Block Product with Factoring

Section IV.F. Block Product with Shaping Capacity

Section IV.G. Slice Product

Section IV.H. Customers who purchase under the Residential Exchange Program or Subscription settlements of the Residential Exchange Program

1. PF Exchange Program Power
2. PF Exchange Subscription Power

A. FULL SERVICE PRODUCT

Purchases of the core Subscription Full Service Product are subject to the charges specified below.

1. Priority Firm Power

1.1 Demand Charge

The charge for Demand will be:
the Purchaser's Measured Demand on the Generation System Peak (GSP) as specified in the contract
multiplied by
the Demand Rate from Section II.A.

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement
as specified in the contract
multiplied by
the HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement
as specified in the contract
multiplied by
the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

The charge for Load Variance will be:
the Purchaser's Total Retail Load for the billing period
multiplied by
the Load Variance Rate from Section II.C.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2002 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost-Based Indexed PF Rate	II.D.
Cost Contributions	II.E.
Cost Recovery Adjustment Clauses	II.F.
Dividend Distribution Clause	II.H.
Flexible PF Rate Option	II.M.
Green Energy Premium	II.N.
Low Density Discount	II.Q.
Rate Melding	II.R.
Targeted Adjustment Charge	II.V.
Unauthorized Increase Charge	II.W.

B. ACTUAL PARTIAL SERVICE PRODUCT - SIMPLE

Purchases of the core Subscription Actual Partial Service Product – Simple are subject to the charges specified below.

1. Priority Firm Power

1.1 Demand Charge

The charge for Demand will be:
(the Purchaser's Demand Entitlement
multiplied by
a Demand Adjuster) as specified in the contract
multiplied by
the Demand Rate from Section II.A.

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement
as specified in the contract
multiplied by
the HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement
as specified in the contract
multiplied by
the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

The charge for Load Variance will be:
the Purchaser's Total Retail Load for the billing period
multiplied by
the Load Variance Rate from Section II.C.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2002 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost-Based Indexed PF Rate	II.D.
Cost Contributions	II.E.
Cost Recovery Adjustment Clauses	II.F.
Dividend Distribution Clause	II.H.
Flexible PF Rate Option	II.M.
Green Energy Premium	II.N.
Low Density Discount	II.Q.
Rate Melding	II.R.
Targeted Adjustment Charge	II.V.
Unauthorized Increase Charge	II.W.

C. ACTUAL PARTIAL SERVICE PRODUCT - COMPLEX

Purchases of the core Subscription Actual Partial Service Product – Complex are subject to the charges specified below.

1. Priority Firm Power

1.1 Demand Charge

The charge for Demand will be:
(the Purchaser's Demand Entitlement
multiplied by
a Demand Adjuster) as specified in the contract
multiplied by
the Demand Rate from Section II.A.

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement
as specified in the contract
multiplied by
the HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement
as specified in the contract
multiplied by
the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

The charge for Load Variance will be:
the Purchaser's Total Retail Load for the billing period
multiplied by
the Load Variance Rate from Section II.C.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2002 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost-Based Indexed PF Rate	II.D.
Cost Contributions	II.E.
Cost Recovery Adjustment Clauses	II.F.
Dividend Distribution Clause	II.H.
Excess Factoring Charges	II.I.
Flexible PF Rate Option	II.M.
Green Energy Premium	II.N.
Low Density Discount	II.Q.
Rate Melding	II.R.
Targeted Adjustment Charge	II.V.
Unauthorized Increase Charge	II.W.

D. BLOCK PRODUCT

Purchases of the core Subscription Block Product are subject to the charges specified below.

1. Priority Firm Power

1.1 Demand Charge

The charge for Demand will be:
the Purchaser’s Demand Entitlement
as specified in the contract
multiplied by
the Demand Rate from Section II.A.

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser’s HLH Energy Entitlement
as specified in the contract
multiplied by
the HLH Energy Rate from Section II.B.

(2) The Purchaser’s LLH Energy Entitlement
as specified in the contract
multiplied by
the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

Not applicable to Block purchases unless the customer is also purchasing another product to which Load Variance is applicable as specified by contract.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2002 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost-Based Indexed PF Rate	II.D.
Cost Contributions	II.E.
Cost Recovery Adjustment Clauses	II.F.
Dividend Distribution Clause	II.H.
Flexible PF Rate Option	II.M.
Green Energy Premium	II.N.
Low Density Discount	II.Q.
Rate Melding	II.R.
Stepped-Up Multiyear Block (SUMY)	II.T.
Targeted Adjustment Charge	II.V.
Unauthorized Increase Charge	II.W.

E. BLOCK PRODUCT WITH FACTORING

Purchases of the core Subscription Block Product with Factoring are subject to the charges specified below.

1. Priority Firm Power

1.1 Demand Charge

The charge for Demand will be:
(the Purchaser’s Demand Entitlement
multiplied by
a Demand Adjuster) as specified in the contract
multiplied by
the Demand Rate from Section II.A.

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser’s HLH Energy Entitlement
as specified in the contract
multiplied by
the HLH Energy Rate from Section II.B.

(2) The Purchaser’s LLH Energy Entitlement
as specified in the contract
multiplied by
the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

Not applicable to Block purchases unless the customer is also purchasing another product to which Load Variance is applicable as specified by contract.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2002 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost-Based Indexed PF Rate	II.D.
Cost Contributions	II.E.
Cost Recovery Adjustment Clauses	II.F.
Dividend Distribution Clause	II.H.
Excess Factoring Charges	II.I.
Flexible PF Rate Option	II.M.
Green Energy Premium	II.N.
Low Density Discount	II.Q.
Rate Melding	II.R.
Stepped-Up Multiyear Block (SUMY)	II.T.
Targeted Adjustment Charge	II.V.
Unauthorized Increase Charge	II.W.

F. BLOCK PRODUCT WITH SHAPING CAPACITY

Purchases of the core Subscription Block Product with Shaping Capacity are subject to the charges specified below.

1. Priority Firm Power

1.1 Demand Charge

The charge for Demand will be:
the Purchaser's Demand Entitlement
as specified in the contract
multiplied by
the Demand Rate from Section II.A.

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement
as specified in the contract
multiplied by
the HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement
as specified in the contract
multiplied by
the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

Not applicable to Block purchases unless the customer is also purchasing another product to which Load Variance is applicable as specified by contract.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2002 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost-Based Indexed PF Rate	II.D.
Cost Contributions	II.E.
Cost Recovery Adjustment Clauses	II.F.
Dividend Distribution Clause	II.H.
Flexible PF Rate Option	II.M.
Green Energy Premium	II.N.
Low Density Discount	II.Q.
Rate Melding	II.R.
Stepped-Up Multiyear Block (SUMY)	II.T.
Targeted Adjustment Charge	II.V.
Unauthorized Increase Charge	II.W.

G. SLICE PRODUCT

Purchases of the Subscription Slice Product are limited to Public Preference Customers and are subject to the charges specified below.

1. Slice Product Charge

The charge for the Slice Product will be:
the elected Slice Percentage expressed as a decimal (.01 = 1%)
multiplied by
100
multiplied by
the Slice Rate in Section II.D.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2002 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost Contributions	II.E.
Load-Based Cost Recovery Adjustment Clause	II.F.1
Low Density Discount	II.Q.
Slice Portion of IOU Settlement	II.X.
Slice True-Up Adjustment	II.S.
Unauthorized Increase Charge	II.W.

H. CUSTOMERS WHO PURCHASE UNDER RESIDENTIAL EXCHANGE PROGRAM OR SUBSCRIPTION SETTLEMENTS OF THE RESIDENTIAL EXCHANGE PROGRAM

The PF Exchange rates include: (1) the PF Exchange Program rate; and (2) the PF Exchange Subscription rate.

1. Priority Firm Exchange Program Power

This PF Exchange Program rate applies to the traditional implementation of the Residential Exchange Program.

a. Priority Firm Exchange Program Power Charges

1.1 Demand Charge

The charge for Demand will be:
the Purchaser's Billing Demand, (which is calculated by applying the load factor, determined as specified in the Residential Exchange Program agreement, to the Billing Energy for each billing period)
multiplied by
the Demand Rate from Section III.A.

1.2 Energy Charge

The monthly charge for energy will be:
the Purchaser's Billing Energy, (which is the energy associated with the utility's residential load for each billing period computed in accordance with the provisions of the Purchaser's Residential Exchange Program agreement)
multiplied by
the Energy Rate from Section III.B.1.

1.3 Load Variance Charge

The charge for Load Variance is embedded in the energy charge.

b. Transmission Charges

Customers purchasing under this rate schedule are charged for transmission services under the Network Transmission (NT) rate schedule or its successor.

Customers purchasing under this rate schedule are charged for Load Regulation under the applicable charge established by the Transmission Business Line (TBL) or its successor.

c. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
Conservation Surcharge	II.B.
Cost Contributions	II.E.
Cost Recovery Adjustment Clauses	II.F.
Dividend Distribution Clause	II.H.
Low Density Discount	II.Q.

2. Priority Firm Exchange Subscription Power

This PF Exchange Subscription rate applies to sales under section 5(c) of the Northwest Power Act to IOUs that participate in a settlement of the Residential Exchange Program as described in BPA's Subscription Strategy.

a. Priority Firm Exchange Subscription Power Charges

1.1 Demand Charge

The charge for Demand will be:
the Purchaser's Contract Demand
multiplied by
the Demand Rate from Section III.A.

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Contract Energy
multiplied by
the HLH Energy Rate from Section III.B.2.

(2) The Purchaser's LLH Contract Energy
multiplied by
the LLH Energy Rate from Section III.B.2.

1.3 Load Variance Charge

Not applicable.

b. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost Contributions	II.E.
Cost Recovery Adjustment Clauses	II.F.
Dividend Distribution Clause	II.H.
Green Energy Premium	II.N.
Unauthorized Increase Charge	II.W.

SECTION V. TRANSMISSION

All customers will need to obtain transmission for delivery of products listed under this rate schedule, except for the exchange product listed under Section IV.H.1.

SCHEDULE RL-02
RESIDENTIAL LOAD FIRM POWER RATE

SECTION I. AVAILABILITY

This schedule is available for the contract purchase of Firm Power to be used within the Pacific Northwest. The Residential Load (RL) Firm Power Rate is available to investor-owned utilities (IOU) under net requirements contracts for resale to ultimate residential consumers for direct consumption. Further, in order to purchase under this rate, the IOU must agree to waive its right to request benefits under section 5(c) of the Northwest Power Act for the term of the contract. Each IOU will be able to purchase a specified amount of Firm Power at the RL-02 rate. Additional sales of requirements power to IOUs will be made at the NR-02 rate.

The product will be delivered in equal hourly amounts over the rate period. The consumer bills of participating IOUs should designate “Federal Columbia River Benefits Supplied By BPA” to describe the amount of benefits each consumer receives.

Rates in this schedule are available for purchases under requirements sales contracts for a five-year period. Only the block product is available under this rate schedule.

Sales under this schedule are subject to BPA’s 2002 General Rate Schedule Provisions (2002 GRSPs) and billing process.

SECTION II. RATES TABLES

The rates for the RL Firm Power product are identified below.

A. DEMAND RATE

1. Monthly Demand for FY 2002 through FY 2006

1.1 Applicability

These rates apply to eligible customers purchasing power for five years.

1.2 Rate Table

Applicable Months	***Rate***
January	$2.16/kW-mo
February	$2.03/kW-mo
March	$1.82/kW-mo
April	$1.45/kW-mo
May	$1.43/kW-mo
June	$1.79/kW-mo
July	$2.31/kW-mo
August	$2.31/kW-mo
September	$2.31/kW-mo
October	$1.76/kW-mo
November	$2.31/kW-mo
December	$2.31/kW-mo

B. ENERGY RATE

1. Monthly Energy Rates for FY 2002 through FY 2006

1.1 Applicability

These rates apply to eligible customers purchasing power for all five years of the rate period.

1.2 Rate Table

Applicable Months	*HLH Rate*	*LLH Rate*
January	20.12 mills/kWh	14.14 mills/kWh
February	18.58 mills/kWh	13.14 mills/kWh
March	16.83 mills/kWh	11.42 mills/kWh
April	13.18 mills/kWh	8.82 mills/kWh
May	13.13 mills/kWh	7.25 mills/kWh
June	16.45 mills/kWh	8.80 mills/kWh
July	21.63 mills/kWh	14.69 mills/kWh
August	32.02 mills/kWh	17.93 mills/kWh
September	22.94 mills/kWh	18.79 mills/kWh
October	16.27 mills/kWh	11.76 mills/kWh
November	22.00 mills/kWh	17.71 mills/kWh
December	22.65 mills/kWh	17.37 mills/kWh

C. LOAD VARIANCE RATE

Not applicable.

SECTION III. BILLING FACTORS AND ADJUSTMENTS

Eligible customers purchasing power under a contract implementing Subscription settlements of the Residential Exchange Program are subject to the charges specified below.

1. Residential Load Firm Power

1.1 Demand Charge

The charge for Demand will be:
the Purchaser's Contract Demand
multiplied by
the Demand Rate from Section II.A.

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Contract Energy
multiplied by
the HLH Energy Rate from Section II.B; and

(2) The Purchaser's LLH Contract Energy
multiplied by
the LLH Energy Rate from Section II.B.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2002 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost Contributions	II.E.
Cost Recovery Adjustment Clauses	II.F.
Dividend Distribution Clause	II.H.
Green Energy Premium	II.N.
Unauthorized Increase Charge	II.W.

SECTION IV. TRANSMISSION

All customers will need to obtain transmission for delivery of products listed under this rate schedule unless BPA's Power Business Line (PBL) and the customer negotiate otherwise at time of sale.

SCHEDULE NR-02
NEW RESOURCE FIRM POWER RATE

SECTION I. AVAILABILITY

This schedule is available for the contract purchase of Firm Power to be used within the PNW. New Resource Firm Power (NR) is available to IOUs under net requirements contracts for resale to ultimate consumers; for direct consumption; and for Construction, Test and Start-Up, and Station Service. NR also is available to any public body, cooperative, or Federal agency to the extent such power is needed to serve any New Large Single Load (NLSL), as defined by the Northwest Power Act. That portion of the utility's load placed on BPA that is attributable to the NLSL will be billed under this rate schedule.

Rates in this schedule are available for purchases under contracts for which power deliveries begin on or after October 1, 2001 (2002 Contract), for a three- or five-year period. Products available under this rate schedule are defined in BPA's 2002 General Rate Schedule Provisions (2002 GRSPs).

This rate schedule supersedes the NR-96 rate schedule, which went into effect October 1, 1996. Sales under the NR-02 rate schedule are subject to BPA's 2002 GRSPs and billing process.

SECTION II. RATES TABLES

The rates in this section apply to NR products.

A. DEMAND RATE

1. Monthly Demand Rate for FY 2002 through FY 2006

1.1 Applicability

These rates apply to eligible customers purchasing power for three or five years.

1.2 Rate Table

Applicable Months	*Rate*
January	$2.16/kW-mo
February	$2.03/kW-mo
March	$1.82/kW-mo
April	$1.45/kW-mo
May	$1.43/kW-mo
June	$1.79/kW-mo
July	$2.31/kW-mo
August	$2.31/kW-mo
September	$2.31/kW-mo
October	$1.76/kW-mo
November	$2.31/kW-mo
December	$2.31/kW-mo

B. ENERGY RATE

1. Monthly Energy Rates for FY 2002 through FY 2004

1.1 Applicability

These rates apply to eligible customers purchasing power in the first three years of the rate period.

1.2 Rate Table

Applicable Months	***HLH Rate***	***LLH Rate***
January	40.87 mills/kWh	28.97 mills/kWh
February	37.79 mills/kWh	26.97 mills/kWh
March	34.32 mills/kWh	23.55 mills/kWh
April	27.06 mills/kWh	18.37 mills/kWh
May	26.95 mills/kWh	15.25 mills/kWh
June	33.56 mills/kWh	18.33 mills/kWh
July	43.86 mills/kWh	30.06 mills/kWh
August	64.54 mills/kWh	36.50 mills/kWh
September	46.48 mills/kWh	38.22 mills/kWh
October	33.21 mills/kWh	24.23 mills/kWh
November	44.60 mills/kWh	36.07 mills/kWh
December	45.90 mills/kWh	35.39 mills/kWh

2. Monthly Energy Rates for FY 2005 through FY 2006

2.1 Applicability

These rates apply to purchases during the last two years of the rate period for eligible customers purchasing for all five years of the rate period.

2.2 Rate Table

Applicable Months	***HLH Rate***	***LLH Rate***
January	42.37 mills/kWh	30.47 mills/kWh
February	39.29 mills/kWh	28.47 mills/kWh
March	35.82 mills/kWh	25.05 mills/kWh
April	28.56 mills/kWh	19.87 mills/kWh
May	28.45 mills/kWh	16.75 mills/kWh
June	35.06 mills/kWh	19.83 mills/kWh
July	45.36 mills/kWh	31.56 mills/kWh
August	66.04 mills/kWh	38.00 mills/kWh
September	47.98 mills/kWh	39.72 mills/kWh
October	34.71 mills/kWh	25.73 mills/kWh
November	46.10 mills/kWh	37.57 mills/kWh
December	47.40 mills/kWh	36.89 mills/kWh

3. Monthly Energy Rates for FY 2002 through FY 2006

3.1 Applicability

These rates apply to eligible customers purchasing for all five years of the rate period under this rate table.

3.2 Rate Table

Applicable Months	*HLH Rate*	*LLH Rate*
January	41.47 mills/kWh	29.57 mills/kWh
February	38.39 mills/kWh	27.57 mills/kWh
March	34.92 mills/kWh	24.15 mills/kWh
April	27.66 mills/kWh	18.97 mills/kWh
May	27.55 mills/kWh	15.85 mills/kWh
June	34.16 mills/kWh	18.93 mills/kWh
July	44.46 mills/kWh	30.66 mills/kWh
August	65.14 mills/kWh	37.10 mills/kWh
September	47.08 mills/kWh	38.82 mills/kWh
October	33.81 mills/kWh	24.83 mills/kWh
November	45.20 mills/kWh	36.67 mills/kWh
December	46.50 mills/kWh	35.99 mills/kWh

C. LOAD VARIANCE RATE

The Load Variance rate for FY 2002 through FY 2006 is applicable to all customers purchasing power under this rate schedule unless specifically excluded in Section III below. The rate for Load Variance is 0.8 mills/kWh.

SECTION III. BILLING FACTORS, AND ADJUSTMENTS FOR EACH NR PRODUCT

This rate schedule contains seven subsections, corresponding to the products to which this rate schedule applies. The following seven products are available to serve NLSLs, or other loads served at the NR-02 rate.

Section III.A.	New Large Single Load
Section III.B.	Full Service Product
Section III.C.	Actual Partial Service Product - Simple
Section III.D.	Actual Partial Service Product - Complex
Section III.E.	Block Product
Section III.F.	Block Product with Factoring
Section III.G.	Block Product with Shaping Capacity

A. NEW LARGE SINGLE LOAD (NLSL) SERVICE PRODUCT

Purchases of New Resource Firm Power to serve a NLSL are subject to the charges specified below.

1. New Resource Firm Power

1.1 Demand Charge

The charge for Demand will be:
the NLSL's Demand Entitlement as
specified in the contract
multiplied by
the Demand Rate from Section II.A.

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2), unless BPA and the Purchaser agree to bill based on a contract amount of energy.

(1) The NLSL's HLH Energy Entitlement as
specified in the contract
multiplied by
the HLH Energy Rate from Section II.B.

(2) the NLSL's LLH Energy Entitlement as
specified in the contract
multiplied by
the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

The charge for Load Variance will be
the NLSL's Measured Energy for the billing period as specified in the contract
multiplied by
the Load Variance Rate from Section II.C.

If the customer is already paying the Load Variance Charge on the NLSL load through this or another rate schedule, this charge does not apply.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2002 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost Contributions	II.E.
Cost Recovery Adjustment Clauses	II.F.
Dividend Distribution Clause	II.H.
Flexible NR Rate Option	II.L.
Green Energy Premium	II.N.
Low Density Discount	II.Q.
Rate Melding	II.R.
Targeted Adjustment Charge	II.V.
Unauthorized Increase Charge	II.W.

B. FULL SERVICE PRODUCT

Purchases of the core Subscription Full Service Product are subject to the charges specified below.

1. New Resource Firm Power

1.1 Demand Charge

The charge for Demand will be:
the Purchaser's Measured Demand on the GSP as
specified in the contract
multiplied by
the Demand Rate from Section II.A.

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement as
specified in the contract
multiplied by
the HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement as
specified in the contract
multiplied by
the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

The charge for Load Variance will be
the Purchaser's Total Retail Load for the billing period
multiplied by
the Load Variance Rate from Section II.C.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2002 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost Contributions	II.E.
Cost Recovery Adjustment Clauses	II.F.
Dividend Distribution Clause	II.H.
Flexible NR Rate Option	II.L.
Green Energy Premium	II.N.
Low Density Discount	II.Q.
Rate Melding	II.R.
Targeted Adjustment Charge	II.V.
Unauthorized Increase Charge	II.W.

C. ACTUAL PARTIAL SERVICE PRODUCT - SIMPLE

Purchases of the core Subscription Actual Partial Service Product – Simple are subject to the charges specified below.

1. New Resource Firm Power

1.1 Demand Charge

The charge for Demand will be:
(the Purchaser's Demand Entitlement
multiplied by
a Demand Adjuster) as specified in the contract
multiplied by
the Demand Rate from Section II.A.

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement as specified in the contract
multiplied by
the HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement as specified in the contract
multiplied by
the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

The charge for Load Variance will be
the Purchaser's Total Retail Load for the billing period
multiplied by
the Load Variance from Section II.C.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2002 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	*2002 GRSPs Section*
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost Contributions	II.E.
Cost Recovery Adjustment Clauses	II.F.
Dividend Distribution Clause	II.H.
Flexible NR Rate Option	II.L.
Green Energy Premium	II.N.
Low Density Discount	II.Q.
Rate Melding	II.R.
Targeted Adjustment Charge	II.V.
Unauthorized Increase Charge	II.W.

D. ACTUAL PARTIAL SERVICE PRODUCT - COMPLEX

Purchases of the core Subscription Actual Partial Service Product – Complex are subject to the charges specified below.

1. New Resource Firm Power

1.1 Demand Charge

The charge for Demand will be:
(the Purchaser's Demand Entitlement
multiplied by
a Demand Adjuster) as specified in the contract
multiplied by
the Demand Rate from Section II.A.

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement as specified in the contract
multiplied by
the HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement as specified in the contract
multiplied by
the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

The charge for Load Variance will be
the Purchaser's Total Retail Load for the billing period
multiplied by
the Load Variance Rate from Section II.C.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2002 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost Contributions	II.E.
Cost Recovery Adjustment Clauses	II.F.
Dividend Distribution Clause	II.H.
Excess Factoring Charges	II.I.
Flexible NR Rate Option	II.L.
Green Energy Premium	II.N.
Low Density Discount	II.Q.
Rate Melding	II.R.
Targeted Adjustment Charge	II.V.
Unauthorized Increase Charge	II.W.

E. BLOCK PRODUCT

Purchases of the core Subscription Block Product are subject to the charges specified below.

1. New Resource Firm Power

1.1. Demand Charge

The charge for Demand will be:
the Purchaser's Demand Entitlement as
specified in the contract
multiplied by
the Demand Rate from Section II.A.

1.2. Energy Charge

The total monthly charge for energy shall be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement as
specified in the contract
multiplied by
the HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement as
specified in the contract
multiplied by
the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

Not applicable to Block purchases unless the customer is also purchasing another product to which Load Variance is applicable as specified by contract.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2002 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost Contributions	II.E.
Cost Recovery Adjustment Clauses	II.F.
Dividend Distribution Clause	II.H.
Flexible NR Rate Option	II.L.
Green Energy Premium	II.N.
Low Density Discount	II.Q.
Rate Melding	II.R.
Stepped-Up Multiyear Block (SUMY)	II.T.
Targeted Adjustment Charge	II.V.
Unauthorized Increase Charge	II.W.

F. BLOCK PRODUCT WITH FACTORING

Purchases of the core Subscription Block Product with Factoring are subject to the charges specified below.

1. New Resource Firm Power

1.1. Demand Charge

The charge for Demand will be:
(the Purchaser's Demand Entitlement
multiplied by
a Demand Adjuster) as specified in the contract
multiplied by
the Demand Rate from Section II.A.

1.2. Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement as
specified in the contract
multiplied by
the HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement as
specified in the contract
multiplied by
the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

Not applicable to Block purchases unless the customer is also purchasing another product to which Load Variance is applicable as specified by contract.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2002 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost Contributions	II.E.
Cost Recovery Adjustment Clauses	II.F.
Dividend Distribution Clause	II.H.
Excess Factoring Charges	II.I.
Flexible NR Rate Option	II.L.
Green Energy Premium	II.N.
Low Density Discount	II.Q.
Rate Melding	II.R.
Stepped-Up Multiyear Block (SUMY)	II.T.
Targeted Adjustment Charge	II.V.
Unauthorized Increase Charge	II.W.

G. BLOCK PRODUCT WITH SHAPING CAPACITY

Purchases of the core Subscription Block Product with Shaping Capacity are subject to the charges specified below.

1. New Resource Firm Power

1.1 Demand Charge

The charge for Demand will be:
the Purchaser's Demand Entitlement as
specified in the contract
multiplied by
the Demand Rate from Section II.A.

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement as
specified in the contract
multiplied by
the HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement as
specified in the contract
multiplied by
the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

Not applicable to Block purchases unless the customer is also purchasing another product to which Load Variance is applicable as specified by contract.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2002 GRSPs. Relevant sections are identified below:

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost Contributions	II.E.
Cost Recovery Adjustment Clauses	II.F.
Dividend Distribution Clause	II.H.
Flexible NR Rate Option	II.L.
Green Energy Premium	II.N.
Low Density Discount	II.Q.
Rate Melding	II.R.
Stepped-Up Multiyear Block (SUMY)	II.T.
Targeted Adjustment Charge	II.V.
Unauthorized Increase Charge	II.W.

SECTION IV. TRANSMISSION

All customers will need to obtain transmission for delivery of products listed under this rate schedule unless BPA's PBL and the customer negotiate otherwise at time of sale. Regulation and Frequency Response may have to be purchased for NLSLs.

IP-02
INDUSTRIAL FIRM POWER RATE

SECTION I. AVAILABILITY

This schedule is available, in conjunction with the Industrial Firm Power Targeted Adjustment Charge (IPTAC), to BPA's direct service industrial customers (DSI) for Firm Power to be used in their industrial operations. DSIs that purchase power under contracts for which power deliveries begin on October 1, 2001 (2002 Contracts), are eligible to purchase under this rate schedule for a five-year period.

This rate schedule supersedes the IP-96 rate schedule, which went into effect October 1, 1996. Sales under the IP-02 rate schedule are subject to BPA's 2002 General Rate Schedule Provisions (2002 GRSPs) and billing process.

SECTION II. RATES TABLES

The rates for the Industrial Firm Power (IP) product are identified below.

A. DEMAND RATE FOR ALL IP/IPTAC PRODUCTS

1. Flat Rate Demand for FY 2002 through 2006

1.1 Applicability

These rates apply to eligible customers purchasing power.

1.2 Rate Table

Applicable Months	*Rate*
January	$2.16/kW-mo
February	$2.03/kW-mo
March	$1.82/kW-mo
April	$1.45/kW-mo
May	$1.43\kW-mo
June	$1.79/kW-mo
July	$2.31/kW-mo
August	$2.31/kW-mo
September	$2.31/kW-mo
October	$1.76/kW-mo
November	$2.31/kW-mo
December	$2.31/kW-mo

B. ENERGY RATE

1. Monthly Energy Rates for FY 2002 through FY 2006

1.1 Applicability

These energy rates are to be combined with one of the two IPTACs specified in section 2.2 or 3.2 below.

1.2 Rate Table

Applicable Months	*HLH Rate*	*LLH Rate*
January	21.86 mills/kWh	15.88 mills/kWh
February	20.31 mills/kWh	14.88 mills/kWh
March	18.57 mills/kWh	13.16 mills/kWh
April	14.92 mills/kWh	10.55 mills/kWh
May	14.86 mills/kWh	8.98 mills/kWh
June	18.18 mills/kWh	10.53 mills/kWh
July	23.36 mills/kWh	16.43 mills/kWh
August	33.76 mills/kWh	19.66 mills/kWh
September	24.68 mills/kWh	20.53 mills/kWh
October	18.01 mills/kWh	13.50 mills/kWh
November	23.74 mills/kWh	19.45 mills/kWh
December	24.39 mills/kWh	19.11 mills/kWh

2. Monthly Energy Rates for FY 2002 through FY 2006 for IPTAC (A)

2.1 These rates apply to eligible customers purchasing power under this rate schedule.

2.2 A charge of 2.02 mills shall be added to each IP energy rate in the Rate Table in section 1.2 above.

3. Monthly Energy Rates for FY 2002 through FY 2006 for IPTAC (B)

3.1 These rates apply to eligible customers purchasing power under this rate schedule.

3.2 A charge of 3.52 mills shall be added to each IP energy rate in the Rate Table in section 1.2 above.

C. LOAD VARIANCE RATE

The Load Variance rate for FY 2002 through FY 2006 applies to all customers purchasing power under this rate schedule unless specifically excluded in Section III below. The rate for Load Variance is 0.8 mills/kWh.

SECTION III. BILLING FACTORS AND ADJUSTMENTS FOR THE IPTAC PRODUCT

Only the firm take-or-pay Block Product is available under this rate schedule. Energy charges for the IPTAC product would apply as specified in Sections II.B.2. and II.B.3.

SECTION III.A. DSI Customers Who Purchase Under 2002 Industrial Firm Power Targeted Adjustment Charge (IPTAC) Contracts.

A. DSI CUSTOMERS WHO PURCHASE UNDER 2002 INDUSTRIAL FIRM POWER TARGETED ADJUSTMENT CHARGE (IPTAC) CONTRACTS

Purchases of power under a 2002 IPTAC contract are subject to the charges specified below.

1. Industrial Firm Power

1.1 Demand Charge

The charge for Demand will be:
the Purchaser's Demand Entitlement as specified in the contract
multiplied by
the Demand Rate from Section II.A.

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement as specified in the contract
multiplied by
the HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement as specified in the contract
multiplied by
the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

Not applicable to Block purchases unless the customer is also purchasing another product to which Load Variance is applicable as specified by contract.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2002 GRSPs. Relevant sections are identified below:

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
Conservation and Renewable Discount	II.A.
Cost-Based Indexed IP Rate	II.C.
Cost Contributions	II.E.
Cost Recovery Adjustment Clauses	II.F.
Dividend Distribution Clause	II.H.
Flexible IP Rate Option	II.K.
Green Energy Premium	II.N.
Industrial Firm Power Targeted Adjustment Charge	II.P.
Rate Melding	II.R.
Supplemental Contingency Reserves Adjustment	II.U.
Unauthorized Increase Charge	II.W.

SECTION IV. TRANSMISSION

All customers will need to obtain transmission for delivery of products listed under this rate schedule unless BPA’s PBL and the customer negotiate otherwise at time of sale.

NF-02
NONFIRM ENERGY RATE

SECTION I. AVAILABILITY

This schedule is available for the purchase of nonfirm energy to be used both inside and outside the United States including sales under the Western Systems Power Pool (WSPP) agreements and sales to consumers. The offer of nonfirm energy under this schedule shall be determined by BPA.

This rate schedule supersedes the NF-96 schedule, which went into effect on October 1, 1996. Sales under the NF-02 rate schedule are subject to BPA's 2002 General Rate Schedule Provisions (2002 GRSPs). For sales under this rate schedule, bills shall be rendered and payments due pursuant to BPA's 2002 GRSPs and billing process.

SECTION II. RATES, BILLING FACTORS, AND ADJUSTMENTS

The average cost of nonfirm energy is 25.18 mills/kWh. The NF-02 rate schedule provides for upward and downward pricing flexibility from this average nonfirm energy cost.

A. RATES FOR NONFIRM ENERGY

1. Standard Rate

The Standard rate is any offered rate not to exceed 30.22 mills/kWh.

2. Market Expansion Rate

The Market Expansion rate is any offered rate below the Standard rate in effect. BPA may have one or more Market Expansion rates in effect simultaneously.

3. Incremental Rate

The Incremental Rate is the Incremental Cost of energy plus 2.00 mills/kWh, where the Incremental Cost is defined as all identifiable costs (expressed in mills/kWh) that BPA would have avoided had it not produced or purchased the energy being sold under this rate.

4. Contract Rate

The Contract Rate is 25.18 mills/kWh.

B. BILLING FACTOR FOR NONFIRM ENERGY

The billing factor for nonfirm energy purchased under this rate schedule shall be the Measured Energy unless otherwise specified by contract.

C. ADJUSTMENTS FOR NONFIRM ENERGY

All adjustments are described in the 2002 GRSPs. The applicable sections are identified for each adjustment.

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
Cost Contributions	II.E.
Unauthorized Increase Charge	II.W.

SECTION III. DETERMINATION OF THE APPLICABLE NF RATE

Any time that BPA has nonfirm energy for sale, the Standard rate, the Market Expansion rate, the Incremental rate, the Contract rate, or any combination of these rates may be in effect.

A. STANDARD RATE

The Standard rate is available for all purchases of nonfirm energy.

B. MARKET EXPANSION RATE

1. Application of the Market Expansion Rate

The Market Expansion rate applies when BPA determines that all markets at the Standard rate have been satisfied and BPA offers additional nonfirm energy.

2. Market Expansion Rate Qualification Criteria

In order to purchase nonfirm energy at the Market Expansion rate, a purchaser must:

a. have a displaceable resource, displaceable purchase of electricity; or

b. be an end-user load with a displaceable alternative fuel source.

In addition, a purchaser must demonstrate one of the following:

a. shutdown or reduction of the output of the displaceable resource associated with that purchase, in an amount equal to the amount of Market Expansion rate energy purchased; or

b. reduction of a displaceable purchase and the output of the resource associated with that purchase, in an amount equal to the amount of Market Expansion rate energy purchased; or

c. shutdown or reduction of the identified output of the resource(s) indirectly in an amount equal to the amount of Market Expansion rate energy purchased (for example, the purchase may be used to run a pumped storage unit); or

d. decrease of an end-user alternate fuel source in an amount equivalent to the amount of Market Expansion rate energy purchased.

3. Eligibility Criteria for Market Expansion Rate

a. When only one Market Expansion rate is offered:

Purchasers satisfying the Market Expansion Rate Qualifying Criteria specified in Section III.B.2 above, who purchased nonfirm energy directly from BPA, are eligible to purchase power under the Market Expansion rate offered if the decremental cost of the qualifying resource, purchase, or qualifying alternative fuel source is lower than the Standard rate in effect plus 2.00 mills/kWh.

Purchasers qualifying under Section III.B.2 who purchase nonfirm energy through a third party are eligible to purchase power under the Market Expansion rate offered if the cost of the qualifying alternative fuel source is lower than the Standard rate in effect plus 4.00 mills/kWh.

b. When more than one Market Expansion rate is offered:

Purchasers qualifying under Section III.B.2 who purchase nonfirm energy directly from BPA are eligible to purchase power under the Market Expansion rate if the decremental cost of the qualifying resource, purchase, or qualifying alternative fuel source is lower than the Standard rate in effect plus 2.00 mills/kWh. The rate applicable to a purchaser will be the highest Market Expansion rate offered that is below the purchaser's qualifying decremental cost *minus* 2.00 mills/kWh.

C. INCREMENTAL RATE

The Incremental rate applies to sales of energy:

1. that is produced or purchased by BPA concurrently with the nonfirm energy sale;

2. that BPA may at its option not produce or purchase; and

3. that has an Incremental Cost greater than the Standard rate (plus the Intertie Charge, if applicable) minus 2 mills.

D. CONTRACT RATE

The Contract rate applies to contracts (except power sales contracts offered pursuant to sections 5(b), 5(c), and 5(g) of the Northwest Power Act) that refer to the Contract rate:

1. for sale of nonfirm energy; or

2. for determining the value of energy.

E. WESTERN SYSTEMS POWER POOL TRANSACTIONS (WSPP)

BPA may make available nonfirm energy for transactions under the WSPP agreement. WSPP sales shall be subject to the terms and conditions specified in the WSPP agreement and will be consistent with regional and public preference. The rate for transactions under the WSPP agreement is any rate within the limits specified by the Standard, Market Expansion, and Incremental rates but may not exceed the maximum rate specified in the WSPP agreement. The rate for WSPP sales may differ from the actual rate offered for non-WSPP transactions in any hour. The rate for WSPP transactions is independent of any other rate offered concurrently under this rate schedule outside the agreement.

F. END-USER RATE

BPA may agree to a rate formula for nonfirm energy purchases by end-users. Such rate or rate formula will be within the limits specified for the Standard and Market Expansion rates but may differ from the actual rates offered during any hour.

SECTION IV. DELIVERY

A. RATE OF DELIVERY

BPA shall determine the amount of nonfirm energy to be made available for each hour. Such determination shall be made for each applicable nonfirm energy rate.

B. GUARANTEED DELIVERY

1. Availability

BPA will determine the amount and duration of nonfirm energy to be offered on a guaranteed basis. Such daily or hourly amounts may be as small as zero or as much as all the nonfirm energy that BPA plans to offer for sale on such days.

2. Conditions

Scheduled amounts of guaranteed nonfirm energy may not be changed except:

a. when BPA and the purchaser mutually agree to increase or decrease the scheduled amounts; or

b. when BPA must reduce nonfirm energy deliveries in order to serve firm loads.

SECTION V. TRANSMISSION

All customers will need to obtain transmission for delivery of products listed under this rate schedule unless BPA’s PBL and the customer negotiate otherwise at time of sale.

BPA'S 2002

GENERAL RATE SCHEDULE PROVISIONS

FOR POWER RATES

Revised FY 2003

Note: These General Rate Schedule Provisions were revised by the 2003 Safety-Net Cost Recovery Adjustment Clause Final Proposal, Administrator's Final Record of Decision, Appendix A (SN-03-A-02). Three GRSPs were revised at that time and the changes are included in this document: Financial-Based Cost Recovery Adjustment Clause (FB CRAC), Safety-Net Cost Recovery Adjustment Clause (SN CRAC), and the Dividend Distribution Clause (DDC).

BONNEVILLE
POWER ADMINISTRATION

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2002 GENERAL RATE SCHEDULE PROVISIONS
Revised FY 2003
By the Safety-Net Cost Recovery Adjustment Clause Rate Case (SN-03)

SECTION I. ADOPTION OF REVISED RATE SCHEDULES AND GENERAL RATE SCHEDULE PROVISIONS

A. Approval of Rates

These 2002 Wholesale Power Rate Schedules and General Rate Schedule Provisions (2002 GRSPs) shall become effective upon interim approval or upon final confirmation and approval by the Federal Energy Regulatory Commission (FERC). BPA has requested that FERC make these rates and 2002 GRSPs effective on October 1, 2001. Approval was granted July 21, 2003. All rate schedules shall remain in effect until they are replaced or expire on their own terms.

As of October 1, 2003, three GRSPs were replaced; they are: Financial-Based Cost Recovery Adjustment Clause (FB CRAC), Safety-Net Cost Recovery Adjustment Clause (SN CRAC), and the Dividend Distribution Clause (DDC). These changes were granted interim FERC approval on October 1, 2003. 105 FERC ¶ 61,006 (2003).

B. General Provisions

These 2002 Wholesale Power Rate Schedules and the 2002 GRSPs associated with these schedules supersede BPA's 1996 rate schedules (which became effective October 1, 1996) to the extent stated in the Availability Section of each rate schedule. These schedules and the 2002 GRSPs shall be applicable to all BPA contracts, including contracts executed both prior to, and subsequent to, enactment of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act). All sales under these rate schedules are subject to the following acts as amended: The Bonneville Project Act, the Regional Preference Act (P.L. 88-552), the Transmission System Act (P.L. 93-454), the Northwest Power Act (P.L. 96-501), and the Energy Policy Act of 1992 (P.L. 102-486).

These 2002 rate schedules do not supersede any previously established rate schedule which is required, by agreement, to remain in effect.

If a provision in an executed agreement is in conflict with a provision contained herein, the former shall prevail.

C. Payment Provisions

Payment must be received by the 20th day after the issue date of the bill (Due Date). If the 20th day is a Saturday, Sunday, or Federal holiday, the Due Date is the next business day. A late payment charge shall be applied each day to any unpaid balance. The late payment charge is calculated by dividing the applicable “Prime Rate” (reported in the “Money Rates” Section of the Wall Street Journal) plus 4 percent; by 365. The applicable “Prime Rate” shall be the rate reported on the first day of the month in which payment is received. The customer shall pay by electronic funds transfer using BPA’s established procedures.

D. Notices

For the purpose of determining elapsed time from receipt of a notice applicable to rate schedule and GRSPs administration, a notice shall be deemed to have been received at 0000 hours on the first calendar day following actual receipt of the notice.

E. Provision for Reassignment of Surplus Transmission Capacity

PBL may reassign transmission capacity that it has reserved for its own use at a price not to exceed the highest of: (1) the original transmission rate paid by PBL; or (2) the applicable transmission provider’s maximum stated firm transmission rate on file at the time of the transmission reassignment. Except for the price, the terms and conditions under which the reassignment is made shall be the terms and conditions governing the original grant by the transmission provider. Transmission capacity may only be reassigned to a customer eligible to take service under the transmission provider’s open access transmission tariff or other transmission rate schedules.

SECTION II. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

A. Conservation and Renewables Discount (C&R Discount)

1. Description of the Discount

To encourage and support the development of conservation projects and renewable resources in the PNW, BPA is offering a C&R Discount to customers purchasing under the Priority Firm Power (PF-02), New Resource Firm Power (NR-02), and Residential Load (RL-02) rate schedules. Purchasers of the Slice product and benefits provided as a cash payment in settlement of the Residential Exchange Program will also be eligible for the C&R Discount.

Customers purchasing under the Industrial Firm Power rate (IP-02) will be eligible to the extent that the C&R Discount does not reduce their effective rate below the DSI floor rate. Regional public agency customers with Pre-Subscription contracts with collared pricing provisions may be eligible for the C&R Discount subject to contract provisions.

The amount of the C&R Discount will be a fixed monthly amount based on the customer's forecasted purchases and Residential Exchange Program settlement benefits from BPA under its Subscription contract. Following the end of the Discount Period (which is the end of the rate period or the customer's contract term, whichever comes first), BPA will evaluate the customer's investments in qualifying conservation and renewable resource projects during the Discount Period. Any customer that has not spent at least as much money on Qualifying Expenditures as the cumulative C&R Discount received from BPA must reimburse the difference to BPA.

Purchasers accepting the monthly C&R Discount agree to abide by the implementation provisions specified in the C&R Discount Implementation Manual.

2. Calculation and Application of the Discount

a. Overview of the Discount

The C&R Discount will be included as a fixed dollar credit in the monthly power bill of each participating customer. The credit will equal the customer's forecasted average monthly Subscription Power Purchases and settlement benefits (in kWh) multiplied by the Unit Discount. (Because the average contract is used, the Unit Discount does not vary by month).

b. **Determination of the "Unit Discount"**

The Unit Discount will equal 0.50 mills/kWh for Subscription Power Purchases and settlement benefits. The Unit Discount for eligible Pre-Subscription contracts will be determined based on individual contract provisions.

c. **Determination of Individual Customer Discounts**

For a participating customer buying power from BPA, the monthly dollar discount will be determined by multiplying the customer's forecasted average monthly Subscription Power Purchases and settlement benefits for each contract year by the Unit Discount.

d. **Determination of Subscription Power Purchases**

1. To determine each customer's average monthly Subscription Power Purchase, BPA will use the customer's Net Requirements purchase, as established in the customer's Subscription contract to calculate the following:

   i. When a customer's contract explicitly calculates Net Requirements purchases for a contract year, the customer's monthly average Subscription Power Purchases are equal to the total annual Net Requirements purchases divided by 12.

   ii. When a customer's contract specifies only the monthly kWh output of the customer's resources, the customer must provide its Account Executive with a monthly load forecast of its Net Requirements purchases. The customer's total annual Net Requirements purchases will then be estimated, for purposes of applying the C&R Discount, by subtracting the customer's forecasted total annual resource output from its forecasted annual Requirements purchases and dividing the result by 12.

2. BPA shall treat benefit amounts provided as cash in settlement of Residential Exchange Program as described in their Subscription settlement contract as Subscription Power Purchases for purposes of this calculation.

e. **Annual Review of Individual Customer Discounts**

At least 30 days prior to the start of each contract year, customers will submit, to their Account Executive, adjustments to the monthly Subscription Power Purchase amounts, referred to in section 2 d. above, as specified in their BPA contract. Subscription Power Purchase increases or decreases of greater than 5 percent, year-to-year, will be reflected in the monthly C&R Discount amounts consistent with section 2 c., above.

f. **Application of the Discount**

i. The C&R Discount will be applied after BPA has determined all other charges and credits on the participating customer's power bill.

ii. BPA will provide the C&R Discount even in those months when the C&R Discount amount is larger than the customer's total power bill amount.

3. Qualifying Expenditures

a. Participating customers shall record all individual Qualifying Expenditures by the categories required for the Final Reconciliation Report to ensure full credit for their conservation and renewable resource activities. Qualifying Expenditures are those that meet technical standards developed by the Regional Technical Forum as approved by BPA.

b. Although BPA will provide the credit on a monthly basis, the customer has no obligation to adhere to any particular expenditure pattern. To retain the full C&R Discount provided by BPA, the participating customer must make Qualifying Expenditures during the Discount Period in an amount equal to, or exceeding, the cumulative C&R Discount received from BPA during the Discount Period.

4. Reporting

a. **Interim Conservation and Renewable Reports**

Participating customers shall submit to BPA annual Interim Conservation and Renewable Reports at the end of each fiscal year of the rate period (*i.e.,* 10/01/01 to 9/30/02, 10/01/02 to 9/30/03, etc.).

The Interim Report shall show the customer's cumulative C&R Discounts received to date and their annual and cumulative Qualifying Expenditures by category. If the report shows that the customer's Qualifying Expenditures are less than or equal to its cumulative C&R Discount receipts by 5 percent or more, the customer must indicate in its report how it plans to adjust its expenditures to ensure that it will retain the full C&R Discount after the Discount Period.

b. **Final Reconciliation Reports**

At the end of the Discount Period the participating customer shall prepare a Final Reconciliation Report. This report shall be submitted and received by BPA one month after the end of the Discount Period (November 1, 2006, for participating customers' purchasing power from BPA for the full five-year rate period).

This report shall identify:

i. The cumulative C&R Discount that the customer has received from BPA during the Discount Period;

ii. The cumulative Dividend Distribution Clause (DDC) amount dedicated to Qualifying Expenditures that the customer has received from BPA during the Discount Period; and

iii. The total Qualifying Expenditures that the customer has made during the Discount Period segregated into the following four categories.

I. Incremental Conservation
II. Renewable Resources
III. Low Income Weatherization
IV. Support Activities (*i.e.,* administrative, advertising, R&D.)

c. **Certification of Incremental Spending**

Each Interim Report and the Final Reconciliation Report shall include language certifying the participating customer's actual incremental spending, such as:

"[Customer] certifies that the expenditures documented in this report are incremental increases in this organization's budget for the current operating year beyond what we planned to spend absent the C&R Discount."

d. **Exemption Language**

If states, municipalities, or other governmental bodies in the BPA service territory require, by law or regulation, that a customer, participating in the C&R Discount, acquire or invest in new conservation and/or a new renewable resource project, then such acquisitions and investments will be deemed as incremental budget increases for the purposes of section 4 c., above.

If any utility, participating in the C&R Discount, reports Qualifying Expenditures amounting to 3 percent or more of its retail revenues, then such expenditures will be deemed as incremental budget increases for the purposes of section 4 c., above.

5. Reimbursement

a. **Customers Whose Expenditures Exceed the Threshold**

No reimbursements are required of any participating customer whose total Qualifying Expenditures over the Discount Period equal or exceed the total cumulative C&R Discount received from BPA.

b. **Customers Whose Expenditures Fall Below the Threshold**

If a participating customer's Final Reconciliation Report shows that the cumulative C&R Discount received from BPA exceed the customer's total Qualifying Expenditures, the customer may take an additional month (for a total of two months after the end of the Discount Period) to make the necessary Qualifying Expenditures and prepare a Revised Final Reconciliation Report. The final report is due to BPA within two months of the end of the Discount Period (which is December 1, 2006, for the five-year customers). If the customer's Qualifying Expenditures still do not equal or exceed its cumulative C&R Discount receipts, the customer must reimburse the difference to BPA. Such reimbursement shall be made within the same two-month grace period and shall be made using the same payment method as the customer uses for paying its wholesale bill.

BPA will not assess interest on any reimbursement paid within the two-month window. However, any payment received after the due date (December 1, 2006, for the five-year customers) shall be subject to a late payment charge as described in their Subscription contract.

6. Revenue Dividends

If BPA declares a Dividend Distribution during this rate period, the first $15 million will be allocated to conservation and renewable resource development. BPA will distribute the C&R portion of any declared dividend in the same manner outlined in this section with the following modifications:

1. In order to receive their portion of the C&R dividend, customers must be actively participating in the basic C&R Discount effort; and

2. Participating customers must spend and report two dollars of additional investment in eligible activities to receive credit toward one dollar of their Dividend Distribution share (*i.e.*, any C&R dividend will be leveraged on a two for one basis).

3. The Unit Discount for participating customers receiving the Dividend Distribution will be reset to reflect the actual amount of the DDC and their Subscription Power Purchases during the months the Dividend Distribution is in effect.

B. Conservation Surcharge

The Conservation Surcharge, where implemented shall be applied in accordance with relevant provisions of the Northwest Power Act, BPA's current Conservation Surcharge policy, and the customer's power sales contract with BPA. The Conservation Surcharge would apply to PF-02 (including Slice purchasers), RL-02, and NR-02 rate schedules.

C. Cost-Based Indexed Industrial Firm Power (IP) Rate

The Cost-Based Indexed IP Rate shall be offered to any DSI Purchaser to serve its aluminum smelter operations, and at BPA's sole discretion to any other DSI Purchaser, where the DSI Purchaser makes a contractual commitment to purchase power for all five years of the rate period from BPA under the Cost-Based Indexed IP Rate.

For DSI aluminum companies, the Cost-Based Indexed IP Rate will provide the monthly price for power by applying a monthly average index price for aluminum, to an established Rate Curve (sliding function) explained below.

The Rate Curve sets the key parameters for determining the monthly power price. This Rate Curve will have: (1) an aluminum midpoint value established at the time the power contract is finalized; (2) an upper pivot point 6 cents/lb., above the aluminum midpoint value which sets an aluminum ceiling price above which the power price will not increase further as aluminum prices rise; and (3) a lower pivot point 6 cents/lb., below the aluminum midpoint value which sets an aluminum floor price below which the power price will not decrease further as aluminum prices fall.

The appropriate IPTAC as specified in Sections II.B.2. and II.B.3. of the IP-02 will establish a power price midpoint of $23.50/MWh or $25.00/MWh for each DSI Purchaser. Depending on the applicable IPTAC rate, a lower rate limit will be set at $19.00/MWh or $20.50/MWh, and an upper rate limit will be set at $28.50/MWh or $30.00/MWh.

A Cost-Based Indexed IP Rate will also be available, at BPA's sole discretion, to non-aluminum DSIs. Any Indexed Rate offered to non-aluminum DSI customers will be designed to recover the equivalent of $23.50/MWh over the rate period, and must be based on a commodity that is a direct product of the purchaser. This commodity must be tied to a commercially recognized price index that is: (1) relied upon by multiple producers; (2) used commercially to set settlement terms between producers and consumers; (3) used for establishing longer term prices and for hedging.

1. Calculation of the Average Annual IPTAC (A) and (B)

The average annual IPTAC rates are calculated from annual billing determinants specified in the IP-02 Rate Schedule. The annual average of all billing determinant, including the monthly IP demand charges, the monthly LLH and HLH IP energy rates, plus the appropriate charge specified in either Sections II.B.2. or II.B.3. of the IP-02 Rate Schedule, are used to calculate the power rate midpoints.

The power price at the midpoint value of IPTAC (A) is 23.5 mills/kWh.
The power price at the midpoint value of IPTAC (B) is 25.0 mills/kWh.

2. Establishing the Rate Curve

The rate curve has three main features: (1) a power price midpoint value of $23.50/MWh or $25.0/MWh; (2) a lower pivot point of $19.00/MWh or $20.50/MWh, the point on the rate curve where the price of energy remains unchanged as the price of aluminum continues to fall; and (3) an upper pivot price of $28.50/MWh or $30.00/MWh, the point on the rate curve where the price of energy remains unchanged as the price of aluminum continues to rise. The following criteria will be used in establishing this rate curve.

a. The aluminum midpoint value of the rate curve shall be established at the average of aluminum forward price swap quotes received by BPA on the day of pricing, plus an appropriate risk premium of up to 2 cents. The aluminum midpoint value will not be set above 74 cents/lb. for aluminum, or below 66 cents/lb. for aluminum.

b. The lower pivot point shall be established on the rate curve at the point the price of aluminum is 6 cents lb., less than the aluminum midpoint value; the lower pivot point will intersect with the lower rate limit. The rate of change from the aluminum midpoint value to the lower pivot point is -$0.75/MWh for each cent/lb., aluminum.

c. The upper pivot point shall be established on the rate curve at the point the price of aluminum is 6 cents/lb., greater than the aluminum midpoint value; the upper pivot point will intersect with the upper rate limit. The rate of change from the aluminum midpoint value to the upper pivot point is $0.833/MWh for each cent/lb., aluminum.

Power prices assessed under this rate curve shall be rounded to the nearest 1/10th or $0.1/MWh.

3. Monthly Rate Determination

The power rate of a DSI Purchaser who has selected the Cost-Based Indexed IP Rate option shall be determined each month for billing purposes. For DSI aluminum companies the monthly power rate is determined by applying the average aluminum price to the rate curve. The following criteria shall be used to calculate the average aluminum price for the billing month.

a. The arithmetic mean of the previous month's London Metal Exchange Aluminum H.G. three month (LME – 3-month) futures contract (US $) shall establish the average aluminum price for the billing month.

b. Such average aluminum price shall be applied to the purchaser's rate curve to determine the power rate for the billing month.

c. Monthly power rates under the Cost-Based Indexed IP Rate shall be a single flat energy rate for each month. There will not be a separate charge for demand and energy.

D. Cost-Based Indexed Priority Firm Power (PF) Rate

The Cost-Based Indexed PF Rate will be offered to all firm load requirements customers who wish to convert their applicable PF rate under their contracts to a market-indexed or floating price adjusted for BPA's risk. The following are features of this rate:

1. BPA and the customer will choose during contract negotiations a mutually agreed reference point and sponsor for the index used. For example, the California-Oregon Border (COB) (location) and the Dow Jones cash or the New York Mercantile Exchange (NYMEX) futures (sponsor), or some other combination to arrive at an agreed upon index.

2. BPA will base the index pricing on a current market forecast of the market index referenced. The expected Net Present Value (NPV) revenue of the forecast index prices will be adjusted by a heavy load hour (HLH) and a light load hour (LLH) Market Index Monthly Adjustment (MIMA) to equal the expected NPV of the applicable PF rates. The MIMA reflects BPA's PF equivalent expected revenues at the time the contract is signed, including an insurance premium to ensure revenue sufficiency.

3. Customers must select this rate for the term of their Subscription contract that the 2002-2006 rate period covers. Customers who choose a contract length of less than five years and wish to renew will be subject to rates established under a new rate case.

4. Billing will be based on: (1) the average of the closing price for the last 15 days of trading if using a futures market such as NYMEX; or (2) the monthly volume weighted average of all posted daily prices if using a cash market such as Dow Jones. The MIMA will be calculated as follows:

Index	=	BPA's current forecast or forward transaction price of the market index referenced
PF	=	Monthly PF demand and HLH and LLH energy rates.
Cost of Insurance	=	The premium on a physical or financial instrument used to mitigate the risk.
MIMA	=	Index price minus PF (forward price or forecast) + Cost of Insurance.

Note: when index price (at contract origination) is above PF, the resulting adjustment before insurance will be the application of a discount. When the index price (at contract origination) is below PF, the resulting adjustment before insurance will be the application of a premium. All adjustments are fixed for the duration of the rate period.

E. Cost Contributions

BPA has made the following resource cost determinations:

1. The forecasted average cost of resources available to BPA under average water conditions is 19.38 mills/kWh.

2. The approximate cost contribution of different resource categories to each rate schedule is as shown in Table A:

Table A

Rate Schedule	***Resource Cost Contribution***		
	Federal Base System	**Exchange**	**New Resources**
PF	100%	0%	0%
IP	51.31%	44.99%	3.70%
NR	51.31%	44.99%	3.70%

F. Cost Recovery Adjustment Clause

There are three sets of conditions under which rate increases under Cost Recovery Adjustment Clause (CRAC) may trigger. The first is the Load-Based CRAC (LB CRAC), which triggers if BPA's augmentation cost exceeds the amount forecast in the May Proposal. The second is the Financial-Based CRAC (FB CRAC), which triggers based on the generation function's forecasted level of accumulated net revenues. The third is the Safety-Net CRAC (SN CRAC), which triggers when, after implementation of the LB and FB CRACs, BPA has or reasonably expects to miss a payment to the Treasury or another creditor.

1. Load-Based Cost Recovery Adjustment Clause

a. Application of the Load-Based Cost Recovery Adjustment Clause

The LB CRAC is a percentage rate adjustment based on BPA's cost of acquiring power to meet BPA's contractual obligations to serve loads in excess of the expected firm capability of the Federal Columbia River Power System (FCRPS).

The LB CRAC will be calculated and applied to the following rates for sales of energy, capacity, and load variance: PF [Preference, Exchange Program, and Exchange Subscription], Industrial Firm Power (IP-02), including under the Industrial Firm Power Targeted Adjustment Charge (IPTAC) and Cost-Based Index Rate, Residential Load (RL-02), New Resource Firm Power (NR-02), and Subscription purchases under Firm Power Products and Services (FPS), excluding revenues generated by the FB CRAC, SN CRAC, and distributions under Dividend Distribution Clause (DDC).

The LB CRAC applies to the 1,000 average megawatts (aMW) power sale portion of the Residential Exchange Program (REP) Settlement, including where power sales are converted to cash payments calculated pursuant to

Section 5(b) of the Residential Exchange Settlement Agreement. The LB CRAC will also apply to the Priority Firm Slice Rate, excluding revenues from the contractual true-up pursuant to the Slice Agreement, and payments pursuant to section X of these GRSPs.

The LB CRAC does not apply to power sales under Pre-Subscription contracts to the extent prohibited by such contracts, the 900 aMW of monetary benefits provided under the financial portion of the REP Settlement, or to BPA's current contractual obligations for Seasonal Irrigation Mitigation sales, including for any eligible customer that converts from Slice to another BPA product.

b. **Definitions**

(1) (AAMTA) "Augmentation Amount Actual" means the amount of actual augmentation required as determined in section f(1) of these GRSPs.

(2) (AAMTF) "Augmentation Amount Forecast" means the forecasted augmentation as determined in section d of these GRSPs.

(3) (ACTUALLBCREVREQ) "Actual LB CRAC Revenue Required" means an amount equal to the actual costs incurred by BPA to acquire AAMTA during any six-month period, and is equal to the sum of ACTUALLBCREVREQ(NS) [for Non-Slice products] and ACTUALLBCREVREQ(S) [for the Slice product].

(4) (ACTUALLBCREVREQ(NS)) "Actual LB CRAC Revenue Required (Non-Slice)" means the portion of the actual costs incurred by BPA to acquire AAMTA during any six-month period purchases apportioned to Non-Slice Rates.

(5) (ACTUALLBCREVREQ(S)) "Actual LB CRAC Revenue Required (Slice)" means the portion of the actual costs incurred by BPA to acquire AAMTA during any six-month period that is apportioned to Slice.

(6) (ADJUST(NS)) "Adjustment to a Purchaser's Non-Slice Monthly Bill" means the adjustment to a customer's monthly power bill for the purchase of energy, capacity and load variance products under Non-Slice Rates in an amount equal to one-sixth (1/6) of the customer's share of the Revenue Difference (REVDIFF[NS]) for the preceding six-month period.

(7) (ADJUST(S)) “Adjustment to a Purchaser’s Slice Monthly Bill” means the adjustment to a customer’s monthly power bill for purchases under Slice in an amount equal to the customer’s share of REVDIFF(S) for the preceding six-month period.

(8) (APP) “Augmentation Pre–Purchase” means the quantity of power under a contract or other binding obligation entered into by BPA at least 120 days prior to the first day of the month for the delivery of AAMTF for a given month.

(9) (BUYDOWN) “Cost of Load Buydown” means the costs that BPA incurs to reduce or eliminate its contractual obligation to deliver firm power to regional customers and thereby lower the AAMTF or AAMTA for a month.

(10) (C&R(NS)) “Conservation and Renewables Discount–Non-Slice” means the total dollars actually credited to all Non-Slice purchasers under the Conservation & Renewable Discount.

(11) (C&R(S)) “Conservation and Renewables Discount–Slice” means the total dollars actually credited to all Slice purchasers under the Conservation & Renewables Discount.

(12) (CUSTREV(NS)) “Customer Revenue with LB CRAC–Non-Slice” means the actual revenues received by BPA from each customer for a given six-month period for the purchase of energy, capacity and load variance service at Non-Slice Rate subject to the LB CRAC, reduced by any C&R(NS) and LDD(NS).

(13) (CUSTREV(S)) “Customer Revenue with LB CRAC - Slice” means the actual revenues received by BPA from each customer for a given six-month period for purchases at the Slice rate subject to the LB CRAC, reduced by any C&R(S) and LDD(S).

(14) (DIURNALACA) “Actual Diurnal Augmentation Cost” means the diurnal cost, in dollars, actually incurred by BPA to acquire AAMTA. Diurnal costs are calculated using monthly flat AAMTA and the diurnal cost of acquiring that AAMTA.

(15) (DIURNALACF) “Diurnal Augmentation Cost Forecast” means the diurnal cost, in dollars, that BPA forecasts it will incur to acquire AAMTF. Diurnal costs are calculated using monthly flat AAMTF amounts and the diurnal cost of acquiring those AAMTF amounts.

(16) (LB CRAC%) "LB CRAC Percentage" means the percentage produced by dividing Net Augmentation Costs Forecasted (NACF) by Total Revenues without LB CRAC (TTREVw/oLBC).

(17) (LBCREV(NS)) "LB CRAC Revenues (Non-Slice) Received by BPA" means the amount of revenues actually received by BPA during any six-month period from the sale of energy, capacity and load variance services at Non-Slice Rates subject to the LB CRAC, as reduced by the C&R(NS) and LDD(NS).

(18) (LBCREV(S)) "LB CRAC Revenues [Slice] Received by BPA" means the amount of revenues actually received by BPA during any six-month period from sales at the Slice rate (WP-A-02, Section II.D.2), reduced by the C&R(S) and LDD(S).

(19) (LDD(NS)) "Low Density Discount Non-Slice" means the total dollars actually credited to all purchasers under Non-Slice Rates subject to the LB CRAC under the Low Density Discount.

(20) (LDD(S)) "Low Density Discount Slice" means the total dollars actually credited to all purchasers under the Slice rate under the Low Density Discount.

(21) (LOAD(NS)) "Non-Slice Load Subject to LB CRAC" means the loads that are served by BPA at Non-Slice Rate that are subject to the LB CRAC.

(22) (LOAD(S)) "Slice Load Subject to LB CRAC" means loads that are served by BPA at the Slice rate. LOAD[S] is to be (1,600/7,070)*100.

(23) (MARRA) "Monthly Augmentation Resale Revenues Actual" means the actual monthly resale revenues determined by multiplying the: (a) sum of: (i) Sales of Existing Augmentation Quantity (SALESMAYAUGA) multiplied by $28.10; and (ii) Sales of New Augmentation Quantity (SALESNEWAUGA) multiplied by $19.26; by (b) the number of hours in the month.

(24) (MARRF) "Monthly Augmentation Resale Revenues Forecasted" means the forecasted monthly resale revenues determined by multiplying the: (a) sum of: (i) Sales of Existing Augmentation Quantity (SALESMAYAUGF) multiplied by $28.10; and (ii) Sales of New Augmentation Quantity (SALESNEWAUGF) multiplied by $19.26; by (b) the number of hours in the month.

(25) (MSC) "Monthly System Capability" means the monthly value obtained by shaping the firm system capability to BPA's firm monthly loads, where firm system capability equals 7,070 aMW of FCRPS capability, less the amount of such capability sold to Slice purchasers. A separate shape will be produced for each separate year in the rate period. These monthly amounts of MSC are established once in the Supplemental Rate Case ROD.

(26) (NACA) "Net Augmentation Cost Actual" means the additional augmentation costs that are actually required to be recovered through application of the LB CRAC. NACA is determined separately for each month in any given six-month period.

(27) (NACF) "Net Augmentation Cost Forecast" means the forecast of additional augmentation costs that are required to be recovered through application of the LB CRAC. NACF is forecasted separately for each month in any given six-month period.

(28) (NACDIFF) "Net Augmentation Cost Difference" means the difference between NAC(120) and NAC(0).

(29) (NSL(A)) "Actual Non-Slice Load" means the actual amount of load served by BPA under Non-Slice Rates during a six-month period.

(30) (NSL(F)) "Forecasted Non-Slice Load" means the amount of load served by BPA during a six-month period under Non-Slice Rates.

(31) "Non-Slice Rates" means all BPA firm power rates, other than the PF Slice Rate and includes PF Preference, PF Exchange Program, PF Exchange Subscription, Industrial Firm Power, Industrial Firm Power Targeted Adjustment Charge and Industrial Firm Power Cost Based Index, Residential Load, New Resource Firm Power and the Firm Power Products and Services Rates.

(32) (OC) "Option Costs" means the costs actually incurred or revenues received by BPA by entering into physical or financial option contracts, or other financial contracts, or to reduce the cost of acquiring the cost of AAMTA or AAMTF.

(33) (PRICE) "Price For Forecasted Augmentation Amounts Not Pre-Purchased" means the forward price per megawatthour (MWh) used by BPA to determine the cost of purchasing power equal to the amount by which AAMTF exceeds APP. The PRICE will be established by BPA through the use of documented quotes for specific quantities from brokers or marketers or publicly available

forward price indices. In each case, it is for electricity delivered at the Mid-Columbia market hub.

(34) (RATE(NS)) "Non-Slice Rates Without LB CRAC" means the Non-Slice rates established by BPA in May 2000 in the Administrator's Record of Decision in BPA Docket WP-02.

(35) (RATE(S)) "Slice Rate without LB CRAC" means the Slice rate established by BPA in May 2000 in the Administrator's Record of Decision in BPA Docket WP-02.

(36) (REVDIFF(NS)) "Revenue Difference Non-Slice" means the amount by which actual LBCREV(NS) exceeds or is less than ACTUALLBCREVREQ(NS) during any six-month period.

(37) (REVDIFF(S)) "Revenue Difference Slice" means the amount by which actual LBCREV(S) exceeds or is less than ACTUALLBCREVREQ(S) during any six-month period.

(38) (REVRATE(NS)) "Adjusted Non-Slice Rates" means the Non-Slice Rates that will apply to sales of energy, capacity and load variance products during the immediately upcoming six-month period.

(39) (REVRATE(S)) "Adjusted Slice Rate" means the Slice rate that will apply to sales of the Slice product during the immediately upcoming six-month period.

(40) (REVw/LBC(NS)) "Actual Non-Slice Revenues" means the monthly revenues actually received by BPA from sales of energy, capacity and load variance products during any six-month period, reduced by the C&R(NS) and LDD(NS).

(41) (REVw/LBC(S)) "Actual Slice Revenues" means the monthly revenues actually received by BPA from sales of the Slice product during any six-month period reduced by C&R(S) and LDD(S).

(42) (REVw/oLBC(NS)) "Baseline Non-Slice Revenues" means the monthly revenues received by BPA from sales of energy, capacity and load variance products subject to LB CRAC using RATE(NS) during any given six-month period reduced by the C&R(NS) and LDD(NS).

(43) (REVw/oLBC(S)) "Baseline Slice Revenues" means the monthly revenues received by BPA from sales of the Slice product during

any given six-month period calculated using RATE(S), reduced by the C&R(S) and LDD(S).

(44) (SALESMAYAUGA) "Actual Sales of Existing Augmentation Quantity" means the resale of augmentation of 1,745 aMW minus [(actual DSI load/1486) * 450].

(45) (SALESMAYAUGF) "Forecasted Sales of Existing Augmentation Quantity" means the resale of augmentation of 1,745 aMW minus [(forecasted DSI load/1486) * 450].

(46) (SALESNEWAUGA) "Sales of New Augmentation Quantity Actual" means the actual monthly amount (in aMW) by which AAMTA is greater than the amount in SALEMAYAUGA.

(47) (SALESNEWAUGF) "Sales of New Augmentation Quantity Forecasted" means the forecasted monthly amount (in aMW) by which AAMTF is greater than the amount in SALEMAYAUGF.

(48) (TAUGCA) "Total Augmentation Cost Actual" means the sum of the monthly DIURNALACA, BUYDOWN and OC amounts for a given six-month period.

(49) (TAUGCF) "Total Augmentation Cost Forecast" means the sum of the monthly DIURNALACF, BUYDOWN, and OC amounts for a given six-month period.

(50) (TARRA) "Total Augmentation Resale Revenue Actual" means the sum of the separate monthly MARRA amounts for a given six-month period.

(51) (TARRF) "Total Augmentation Resale Revenue Forecasted" means the sum of the separate monthly MARRF amounts for a given six-month period.

(52) (TCAPPA) "Total Cost of Augmentation Pre-Purchases Actual Non-Slice" means the actual total cost to acquire APPA(NS).

(53) (TCAPPF) "Total Cost of Augmentation Pre-Purchases Forecasted" means the forecasted total cost of the APP made for a month.

(54) (TREVw/LBC(NS)) "Total Revenues for Non-Slice With LB CRAC" means the sum of all REVw/LBC(NS) for any given six-month period.

(55) (TREVw/LBC(S)) "Total Revenues for Slice with LB CRAC" means the sum of all REVw/LBC(S) for any given six-month period.

(56) (TTREVw/LBC) "Total Revenues with LB CRAC" means the sum of TREVw/LBC(S) and TREVw/LBC(NS).

(57) (TREVw/oLBC(NS)) "Total Non-Slice Revenues Without LB CRAC" means the sum of all REVw/oLBC(NS) for any given six-month period.

(58) (TREVw/oLBC(S)) "Total Slice Revenues without LB CRAC" means the sum of all REVw/oLBC(S) for any given six-month period.

(59) (TTREVw/oLBC) "Total Revenues without LB CRAC" means the sum of TREVw/oLBC(S) and TREVw/oLBC(NS).

(60) (TLA) "Transmission Loss Adjustment" means the Network loss factor adjustment applied under applicable BPA Transmission Business Line tariffs.

c. **Procedure**

Step One below addresses the calculations for determining the LB CRAC percentages that will apply to each six-month period. Step Two below addresses the determination of any rebate or surcharge due to actual LB CRAC exceeding or falling short of the actual costs incurred by BPA to acquire power after the end of the preceding six-month period. This section also describes the procedure by which BPA will provide public process on the application of the LB CRAC.

(1) Step One is calculation of the LB CRAC percentage and resulting adjustment to the rates that will be applied in each six-month period. On or about 90 days prior to the beginning of each six-month period (or in the case of the calculation of the LB CRAC to be applied for the period April 1 through September 30, 2002, on or about 45 days prior to the beginning of that second six-month period), BPA will establish the LB CRAC percentage and resulting adjustment to the rates that will apply to the sale of products under rates subject to the LB CRAC during upcoming six-month period. Using the process described in c(3) below, BPA will determine what data must be revised to develop the LB CRAC for the next six-month period. As a result of rate mitigation efforts, the

Step One analysis will occur in two parts. This two-part process is designed to address the problem of some rate mitigation contracts containing pricing that is itself tied to the LB CRAC. For power buybacks made at a premium above the base rate plus the LB CRAC, in part one, BPA will: (a) include the premium portion of any such agreement; and (b) exclude the quantities of any such agreement from the calculation of REVw/LBC(S) and REVw/oLBC(NS). The increment in rates applicable to any such rate mitigation agreement from part one will then be added to the cost of meeting augmentation used in the calculation of the LB CRAC% in part two. Then, in part two the LB CRAC% and REVRATE will be determined. It is this set of adjusted rates that will appear on customer's bills.

(2) Step Two is the calculation of the amount by which actual LB CRAC revenues exceeded or fell short of the actual costs incurred by BPA to acquire power for the most recently concluded six-month period. As is described below, this calculation does not require a new calculation of the LB CRAC percentage or rates. The amount by which actual LB CRAC revenue exceeded or fell short of actual power costs will be established on or about 90 days after the end of the most recent six-month period. Any such excess or shortfall will be treated separately from any LB CRAC adjustment for the upcoming six-month period. A part of this determination involves revising data from that used to develop the LB CRAC in c(1) immediately above.

(3) Fifteen days prior to the date that BPA must establish the LB CRAC Percentage pursuant to paragraph c(1) above, and any charge or rebate for the amount of any excess or short-fall from the preceding six-month period, BPA will conduct a publicly noticed workshop. For the calculations to be performed for the first six-month period, BPA shall hold two workshops approximately 14 days apart, with the first workshop on or about June 6, 2001. The purpose of the workshop before a six-month period will be to provide customers with information used by BPA to develop the LB CRAC Percentage and adjusted rates for the next six-month period. The information used to perform these calculations will be provided to customers at a quarterly level of aggregation. The purpose of the workshop after a six-month period will be to determine any additional charge or rebate due individual customers for any excess or shortfall of actual LB CRAC revenue to cover NACA from the preceding six-month period. The information used to perform these calculations will be at a quarterly level of aggregation (including total and individual customer revenues used

for such calculations). These workshops will provide customers with an opportunity to ask questions about BPA's calculations, and to provide BPA with information relevant to the calculation of the LB CRAC Percentage, adjusted rates, and any proposed charge or rebate.

d. **Revenue and cost calculations performed before each six-month period**

Before the six-month period, these calculations are performed with forecasted amounts to determine the LB CRAC Percentage and revised rates to be applied to purchaser bills during that period.

(1) Calculating AAMTF

This is a two-step process.

(i) Step One – Forecasted Non-Slice Loads (NSL(F))

In this step, BPA will determine what, if any, changes are required in the Forecasted Non-Slice loads contained in the Supplemental ROD.

(ii) Step Two – Forecasted Augmentation Amount (AAMTF)

For each month separately, AAMTF = (NSL(F) – MSC) * (1 + TLA)

(2) Calculating the DIURNALACF

In this calculation, BPA establishes the costs it expects to incur to acquire AAMTF for each diurnal period for each month in the six-month period.

The following calculations will be separately performed for the HLH in a month and the LLH in each month in the next six-month period.

(i) If APP is greater than AAMTF,
DIURNALACF = (AAMTF/APP) * [TCAPPF]

(ii) If APP is equal to AAMTF,

DIURNALACF = TCAPPF

(iii) If APP is less than AAMTF,

DIURNALACF = [TCAPPF] + [(AAMTF-APP) * PRICE * Diurnal Hours]

(3) Calculating Total Augmentation Cost Forecast for a six-month period

BUYDOWN and OC obligations incurred as of the date of the forecast, and DIURNALCF monthly values for a six-month period will be summed to determine the Total Augmentation Cost Forecast (TAUGCF) for the six-month period.

TAUGCF = Sum of the six monthly (DIURNALACF + BUYDOWN + OC)

(4) Calculating Monthly and Total Augmentation Resale Revenues

This calculation establishes the resale revenue amount to be subtracted from TAUGCF for the six-month period.

The definitions of SALESMAYAUGF and SALESNEWAUGA for both the setting of the LB CRAC% and determining any credit or debit are modified to properly address the calculation of augmentation resale revenue to reflect rate mitigation.

SALESMAYAUGF = Minimum[AAMTF, (1,745 aMW – [(forecasted DSI load reduction/1486)*450])].

SALESNEWAUGF = MAX [0, AAMTF – SALESMAYAUGF]

MARRF = [(SALESMAYAUGF * $28.10) + (SALESNEWAUGF* $19.26)] * Hours in the month

TARRF = Sum of MARRF for each month in a six-month period

(5) Calculating Net Augmentation Cost Forecast for a six-month period

Once the TARRF is established, the NACF will be determined. This is the amount of forecasted costs that must be recovered in an LB CRAC mechanism.

NACF = TAUGCF - TARRF

(6) Calculating Monthly Revenues

This calculation determines the monthly revenues BPA receives from the sale of energy, capacity, and load variance products, including Slice, at rates that are subject to LB CRAC before the application of the LB CRAC.

For the Slice rate,

REVw/oLBC(S) = [RATE(S) * LOAD(S)] – LDD(S) – C&R(S)

Because the Slice rate is stated as $/% per month, REVw/oLBC(S), LOAD(S) is calculated using the percentage of Slice contracted, for example, 28.29% = 2,000 aMW of Slice. For Slice calculations, LDD(S) and C&R(S) are calculated as dollars. That is, LOAD(S) = (actual Slice load/7070)*100.

For Non-Slice Rates for Part One:

REVw/oLBC(NS) = [RATE(NS) * LOAD(NS) * Hours in month] – LDD(NS) – C&R(NS) – [the energy quantity of rate mitigation deals tied to LB CRAC from the Slice contracts * $27.5/MWh] – [the energy quantities of rate mitigation deals tied to LB CRAC from non-Slice contracts * $19.26/MWh]

For Non-Slice Rates for Part Two:

REVw/oLBC(NS) = [RATE(NS) * LOAD(NS) * Hours in month] – LDD(NS) – C&R(NS)

Because Non-Slice Rates are stated as $/MWh and $/kW-month, LOAD(NS) is expressed in MWh and kW for the month. LDD(NS) and C&R(NS) are values of the discounts in dollar amounts.

(7) Calculating Total Revenues without the LB CRAC for a six-month period

TREVw/oLBC(S) = ∑REVw/oLBC(S) for each month in six-month period.

TREVw/oLBC(NS) = ∑REVw/oLBC(NS) for each month in six-month period.

TTREVw/oLBC = TREVw/oLBC(S)+TREVw/oLBC(NS)

e. **Calculation of the LB CRAC percentage and revised rates for Slice and Non-Slice products**

Calculations under this section e only occur once in advance of each six-month period to make the adjustment that will apply to the upcoming six-month period. When the six-month period is over, the calculations in section f are performed.

(1) Calculating the LB CRAC Percentage

LB CRAC% = NACF/TTREVw/oLBC

(2) Calculating the adjustment to RATE(NS) and RATE(S)

(i) Slice Rate

The spreadsheet model defines a variable Multiplier(S) which equals the bracketed term:
Multiplier (S) = {[((TREVw/oLBC(S) + LDD(S)) * LB CRAC%) + (TREVw/oLBC(S) + C&R(S) + LDD(S))]/[TREVw/oLBC(S) + C&R(S) + LDD(S)]}

REVRATE(S) = RATE(S) * Multiplier(S)

(ii) Non-Slice Rates

The spreadsheet model defines a variable Multiplier(NS) which equals the bracketed term:

Multiplier (NS) = {[((TREVw/oLBC(NS) + LDD(NS)) * LB CRAC%) + (TREVw/oLBC(NS) + C&R(NS) + LDD(NS))]/[TREVw/oLBC(NS) + C&R(NS) + LDD(NS)]}

REVRATE(NS) = RATE(NS) * Multiplier(NS)

(3) Application of Revised Rates

The REVRATE(S) and REVRATE(NS) will replace the RATE(S) and RATE(NS), respectively, on purchaser's bills for products sold in the next six-month period that are subject to the LB CRAC.

f. **Calculations performed after the close of each six-month period**

After the six-month period, these calculations are performed with actual amounts to determine the amount of any adjustment to individual customer bills as a result of an over or under collection of LB CRAC revenues.

(1) Calculating AAMTA

This is a two-step process.

(i) Step One – Actual non-Slice Loads (NSL(A))

In this step, BPA will determine the actual non-Slice loads.

(ii) Step Two – Actual Augmentation Amount (AAMTA)

For each month separately, AAMTA = (NSL(A) – MSC) * (1+ TLA).

(2) Calculating DIURNALACA

In this calculation, BPA establishes the costs it actually did incur to acquire AAMTA for each diurnal period for each month in the six-month period.

The following calculations will be separately performed for the HLH in a month and the LLH in each month in the proceeding six-month period.

(i) If APP is greater than AAMTA,

DIURNALACA = (AAMTA/APP) * [TCAPPA]

(ii) If APP is equal to AAMTA,

DIURNALACA = TCAPPA

(iii) If APP is less than AAMTA,

DIURNALACA = [TCAPPA] + [(AAMTA-APP) * PRICE * Diurnal Hours]

(3) Calculating Total Augmentation Cost Actual for a six-month period

Once DIURNALACA, BUYDOWN, and OC are determined, these monthly values for a six-month period will be summed to determine the Total Augmentation Cost Actual (TAUGCA) for the six-month period.

TAUGCA = Sum of the six monthly (DIURNALACA + BUYDOWN + OC)

(4) Calculating Monthly and Total Augmentation Resale Revenues

This calculation establishes the resale revenue amount to be subtracted from TAUGCA for the six-month period.

SALESMAYAUGA = Minimum[AAMTA, (1,745 aMW – [(actual DSI load reduction/1486)*450])].

SALESNEWAUGA = MAX[0, AAMTA – SALESMAYAUGA]

MARRA = [(SALESMAYAUGA * $28.10) + (SALESNEWAUGA * $19.26)] * Hours in the month

TARRA = Sum of MARRA for each month in a six-month period

(5) Calculating Net Augmentation Cost Actual for a six-month period

Once the TARRA is established, the NACA will be determined. This is the actual costs that must be recovered in an LB CRAC mechanism.

NACA = TAUGCA - TARRA

(6) Calculating Monthly Revenues

(i) This calculation determines the monthly revenues BPA *would have* received from the sale of energy, capacity, and load variance products, including Slice, at rates that are subject to LB CRAC before the application of the LB CRAC, but using actual loads.

For the Slice rate,

REVw/oLBC(S) = [RATE(S) * LOAD(S)] – LDD(S) – C&R(S)

Because the Slice rate is stated as $/% per month, REVw/oLBC(S), LOAD(S) is calculated using the percentage of Slice contracted, for example, 28.29% = 2,000 aMW of Slice. That is, LOAD(S) = (actual Slice load/7070) * 100.

For Non-Slice rates,

REVw/oLBC(NS) = [RATE(NS) * LOAD(NS) * Hours in month] – LDD(NS) – C&R(NS)

Because Non-Slice rates are stated as mills/kWh and $/kW-month, LOAD(NS) is expressed in kWh and kW for the month.

(ii) Calculating Actual Monthly Revenues received

This calculation determines the monthly revenues BPA *actually did* receive from the sale of energy, capacity, and load variance products, including Slice, at rates that are subject to LB CRAC *after* the application of the LB CRAC, but using actual loads.

For the Slice rate,

REVw/LBC(S) = [REVRATE(S) * LOAD(S)] – LDD(S) – C&R(S)

Because the Slice rate is stated as $/% per month, REVw/oLBC(S), LOAD(S) is calculated using the percentage of Slice contracted, for example, 28.29% = 2,000 aMW of Slice. That is, LOAD(S) = (actual Slice load/7070) * 100.

For Non-Slice rates,

REVw/LBC(NS) = [REVRATE(NS) * LOAD(NS) * Hours in month] – LDD(NS) – C&R(NS)

Because Non-Slice rates are stated as $/MWh and $/kW-month, LOAD(NS) is expressed in MWh and kW for the month.

(7) Calculating Total Revenues for a six-month period

(i) Without the LB CRAC applied

TREVw/oLBC(S) = ∑REVw/oLBC(S) for each month in six-month period.

$TREVw/oLBC(NS) = \sum REVw/oLBC(NS)$ for each month in six-month period.

$TTREVw/oLBC = TREVw/oLBC(S)+TREVw/oLBC(NS)$

(ii) With the LB CRAC applied

$TREVw/LBC(S) = \sum REVw/LBC(S)$ for each month in six-month period.
$TREVw/LBC(NS) = \sum REVw/LBC(NS)$ for each month in six-month period.

$TTREVw/LBC = TREVw/LBC(S)+TREVw/LBC(NS)$

g. **Determining the surcharge or rebate at the close of a six-month period**

The calculations in this Section g are made once for each six-month period. They are applied only after a six-month period and are used to determine whether the costs incurred by BPA to acquire AAMTA during the preceding six-month period were more or less than the LB CRAC revenues actually received by BPA during such six-month period. The calculations in this Section will be performed as soon as the necessary actual data is available after each six-month period. There are four steps involved in this determination.

Step One: Calculate the LB CRAC revenues that were actually collected during the six-month period separately for Slice and Non-Slice sales;
Step Two: Calculate the LB CRAC revenues that are needed to cover the AAMTA power costs incurred by BPA during the six-month period, divided between Slice and Non-Slice products based on actual LB CRAC revenues;
Step Three: Calculate the difference between Step One and Step Two for Slice and Non-Slice products separately;
Step Four: Calculate the change in cost of meeting AAMTA associated with using the NACA(120) and NACA(0).
Step Five: Calculate the adjustment to the bill of each customer.

(i) Step One

$LBCREV(S) = TREVw/LBC(S) – TREVw/oLBC(S)$

$LBCREV(NS) = TREVw/LBC(NS) – TREVw/oLBC(NS)$

(ii) Step Two

ACTUALLBCREVREQ(S) = [NACA * (TREVw/LBC(S)/TTREVw/LBC)]

ACTUALLBCREVREQ(NS) = [NACA * (TREVw/LBC(NS)/TTREVw/LBC)]

(iii) Step Three

REVDIFF(S) = LBCREV(S) - ACTUALLBCREVREQ(S)

REVDIFF(NS) = LBCREV(NS) - ACTUALLBCREVREQ(NS)

(iv) Step Four

In this step, the difference in cost associated with meeting AAMTA for the six-month period between NACA(0) and NACA(120) is determined. The difference will be referred to as:

NACDIFF = NACA(0) – NACA(120).

(v) Step Five

There will be a separate line item on the bill of each customer purchasing products at rates subject to the LB CRAC reflecting a debit or a credit, and referred to as ADJUST(S) for the Slice rate and ADJUST(NS) for Non-Slice Rates.

(a) Bill Adjustment for a Slice purchaser.

ADJUST(S) = {REVDIFF(S) * [CUSTREV(S)/TREVw/LBC(S)]}/6

(b) Bill Adjustment for Purchaser of Non-Slice products subject to the LB CRAC.

ADJUST(NS) = {[REVDIFF(NS) + NACDIFF] * [CUSTREV(NS)/TREVw/LBC(NS)]}/6

(c) Each of these bill adjustments (ADJUST(NS)) (ADJUST(S)) will initially be added to the bill beginning the month following their finalization and shall continue for a six-month period. BPA and the purchaser may agree to a different payment schedule for any six-month period. For the first six-month period, since customers proposed two 3-month calculations, the results of the first 3-month calculation, scheduled for mid-February 2002, will be spread across 3 months, while the second 3-month adjustment, scheduled for June 2002, will be spread across six months (this assures no overlap between bill adjustments for the actual LB CRAC costs for this first six-month period).

1. Financial-Based Cost Recovery Adjustment Clause*

The FB CRAC is a temporary, upward adjustment to posted power rates for certain Subscription sales which occurs if end-of-year Accumulated Net Revenues (ANR) in the generation function are forecasted to fall below a threshold level.

The FB CRAC applies to power customers under these firm power rate schedules:

- PF [Preference (excluding Slice), Exchange Program, and Exchange Subscription];
- Industrial Firm Power (IP-02), including under the Industrial Firm Power Targeted Adjustment Charge (IPTAC) and Cost-Based Index Rate;
- Residential Load (RL-02);
- New Resource Firm Power (NR-02);
- Subscription purchases under Firm Power Products and Services (FPS);
- the 1,000 aMW power sale portion of the REP Settlement, including where power sales are converted to cash payments calculated pursuant to Section 5(b) of the Residential Exchange Settlement Agreement.

The FB CRAC does not apply to:

- power sales under Pre-Subscription contracts to the extent prohibited by such contracts;
- purchases under the PF Slice Rate;
- the 900 aMW of financial benefits provided under the financial portion of any Residential Exchange Program (REP) Settlement;
- BPA's contractual obligations for Seasonal and Irrigation Mitigation sales, including for any eligible customer that converts from Slice to another BPA product.

* Section II.F.2 (FB CRAC) is reproduced with the section numbering from the 2003 Safety-Net Cost Recovery Adjustment Clause Final Proposal Administrator's Final Record of Decision Appendix A (SN-03-A-02) Page A-1, Section 1. Because of this, the numbering is not consistent throughout the GRSPs.

A. Formula for Calculation of the Financial-Based Cost Recovery Adjustment Clause

By August of the fiscal year immediately prior to each fiscal year of the rate period (*i.e.*, FY 2002-2006), a forecast of that end-of-year ANR will be completed. If the ANR at the end of the forecast year falls below the FB CRAC Threshold applicable to that fiscal year, the FB CRAC will trigger, and a CRAC rate increase will go into effect beginning in October of the upcoming fiscal year.

The Revenue Amount will be determined by the following formula:

Revenue Amount is the lower of:

FB CRAC Threshold minus forecasted ANR;

or

The annual Maximum Planned Recovery Amount, shown in Table A below.

Table A: FB CRAC
[Dollars in Millions]

Applicability to Fiscal Year	ANR Calculated at end of Fiscal Year	FB CRAC Thresholds	Maximum FB CRAC Recovery Amounts
2004	2003	-$378	$150
2005	2004	-$204	$150
2006	2005	-$161	$175

Where Revenue Amount is the amount of additional revenue that an increase in rates under FB CRAC is intended to generate during the period that the rate increase is effective.

Where FB CRAC Threshold is the "trigger point" for invoking a rate increase under the FB CRAC. The Threshold is pre-specified for the end of FY 2003, 2004, and 2005, in Table A.

Where ANR is generation function net revenues, as accumulated since 1999, at the end of each of the FY 2001-2005. Audited Actual Accumulated Net Revenues (AANR), confirmed by BPA's independent auditing firm, will be used for FY 1999 and 2000, and any subsequent year for which they are available. Unaudited ANR will be used to the extent audited actuals are not available.

The forecast of ANR through the end of each fiscal year will be calculated and used to determine if the threshold has been reached, and what the Revenue Amount is. Net revenues for any given fiscal year are accrued revenues less accrued expenses, in accordance with Generally Accepted Accounting Principles, with the following three exceptions. First, for purposes of determining if the FB CRAC threshold has been reached, actual and forecasted expenses will include BPA expenses associated with Energy Northwest debt service as forecasted in the WP-02 Final Studies. Second, those actual and forecasted expenses will include BPA expenses associated with payments of benefits to the Investor-Owned Utilities as forecasted in the SN-03 Final Proposal.[1] Third, the impact of adopting Financial Accounting Standard 133, Accounting for Derivative Instruments and Hedging Activities, will not be considered in determining if the FB CRAC threshold has been reached. Only generation function revenues and expenses, that is, actual and forecasted revenues and expenses that are associated with the production, acquisition, marketing, and conservation of electric power, will be included in determinations under the FB CRAC. Accrued revenues and expenses of the transmission function are excluded. Impacts of forecasted revenues, positive or negative, from contractual true-up pursuant to the Slice Agreement shall be included in the revenue forecast when determining the FB CRAC. As part of BPA's annual audit process, BPA's independent outside auditing firm will confirm that BPA's ANR determination was consistent with applicable criteria. This confirmation will be made in accordance with additional agreed-upon procedures established by BPA and its independent outside auditing firm after consultation with interested parties.

<u>Where Maximum Planned Recovery Amount</u> is the maximum annual amount planned to be recovered through the FB CRAC.

The thresholds for the ends of FY 2003-2005 will be set to be equal to the thresholds for the SN CRAC each time the SN CRAC thresholds are recalculated.

Once the Revenue Amount is determined, that amount will be converted to the FB CRAC Percentage. The FB CRAC Percentage is the percentage increase in customers' rates (not including any CRACs) in each of the firm

[1] This exclusion has been made so that the expense impact of any change to these benefits will not affect the annual calculation of the SN CRAC rate. (It would not be possible at the time of change, e.g., a settlement of the Public-IOU litigation, to be certain what the expense impacts would be; that could depend on an opinion of BPA's auditors which might not be rendered until several months after conclusion of such a settlement.) The impact on rates will be made through the Contingent Recalculation of the SN CRAC parameters.

power rate schedules listed above. This percentage will be applied to generate the additional FB CRAC revenue.

The FB CRAC Percentage will be determined by the following formula:

FB CRAC Percentage =

Revenue Amount

Divided by

FB CRAC Revenue Basis

Where for FY 2002, the FB CRAC Revenue Basis is the total generation revenue (not including LB CRAC) for the loads subject to FB CRAC for the fiscal year in which the FB CRAC implementation begins, based on the then most current revenue forecast. For FY 2003-2006, FB CRAC Revenue Basis is the total generation revenue (not including any CRACs) for the loads subject to FB CRAC plus Slice loads for the fiscal year in which the FB CRAC implementation begins, based on the then most current revenue forecast. Each non-Slice product's total charge for energy, demand, and load variance will be increased by this FB CRAC percentage amount.

Rate increases under the FB CRAC will be due in 12 monthly payments from November (for the October billing period) through October of the following year.

B. FB CRAC Adjustment Timing

In August prior to the beginning of each year of the rate period, the Administrator will determine whether the expected value of the ANR forecast at the end of that current fiscal year is below the FB CRAC Threshold. If the ANR is forecasted to fall below the FB CRAC Threshold, the Administrator will propose, by the end of August, to assess a cost recovery adjustment to applicable rates for power deliveries beginning in October.

Each customer will be notified, on or about September 1, of the percentage increase in rates due to the FB CRAC. The rates used to calculate the customers' bills for the following October through September will reflect the FB CRAC increase.

C. FB CRAC Notification Process

BPA shall use the following notification procedures:

(1) Financial Performance Status Reports

Each quarter, BPA shall post on its electronic information access (World Wide Web) site, preliminary, unaudited, year-to-date aggregate financial results for generation, including ANR.

By January of each year, BPA shall post on its web site the audited AANR attributable to the generation function for the prior fiscal year ending September 30.

In May and August of each year, BPA shall post on its web site an end-of-year forecast of ANR attributable to the generation function.

(2) Actions to mitigate the need for the FB CRAC

If accumulated net revenues at the end of a fiscal year are within $150 million of the FB CRAC threshold for the subsequent year, BPA will prepare and post on its Web site an analysis for the causes of BPA's financial decline compared to the rate case plan, and propose a prioritized list of potential actions to avert or mitigate the need for FB CRAC in future years. BPA shall conduct a public comment period on these actions to avert or reduce a potential FB CRAC rate adjustment by the following October.

(3) Notice of FB CRAC Trigger

BPA shall complete a forecast of end-of-year ANR in August of each year. BPA shall notify all customers and rate case parties by the end of August, in each FY 2001-2005, if the expected value of ANR is forecasted to fall below the FB CRAC Threshold for that fiscal year and, if so, the extent to which BPA intends to adjust rates under the FB CRAC. Notification will include the audited AANR for the prior FY, the forecast of end-of-year ANR, the calculation of the Revenue Amount, and the FB CRAC Percentage. The notice shall also describe the data and assumptions relied upon by BPA. Such data, assumptions, and documentation, if non-proprietary and/or non-privileged, shall be made available for review at BPA upon request. The notice shall also contain the tentative schedule for the remainder of the FB CRAC implementation process.

In early September, for any year in which the ANR is forecasted to fall below the FB CRAC Threshold, BPA staff shall conduct a public forum to explain the ANR forecast, the calculation of the Revenue Amount and the FB CRAC Percentage, and demonstrate that the FB CRAC has been implemented in accordance with the GRSPs. The forum will provide an opportunity for public comment.

On or about September 30 of any fiscal year in which the ANR is forecasted to fall below the FB CRAC Threshold, the Administrator shall provide all customers the calculation of the adjustment and the resulting rate increase (as a percentage) applicable to each rate schedule.

D. True-up

There will be an opportunity for truing-up the FB CRAC Revenue Amount and each customer's portion of it, based on updated data. When audited actuals are available, in January in the year subsequent to the FB CRAC being implemented, the AANR will be compared to the ANR forecast used to implement the FB CRAC. If the forecasted amount is within $5 million of the AANR (the tolerance), no true-up will be made. If AANR differs from the forecast by more than the tolerance, an adjustment will be made in customer bills for the second half of the year. The adjustment will be made as follows:

FB CRAC Adjustment = (difference between the originally calculated FB CRAC Revenue Amount and Revenue Amount calculated using AANR)

divided by

generation revenue (not including LB CRACs) for the loads subject to FB CRAC, as forecasted for power deliveries for April through September.

The resulting percentage will be used to adjust the FB CRAC Percentage applied to each customer's bills for April through September. The total amount collected, however, will not exceed the Maximum Planned Recovery Amount.

E. Contingent Recalculation of SN CRAC Parameters and Thresholds for FB CRAC and SN CRAC Rebate

In August 2003, the parameters of the SN CRAC (the three annual Thresholds and the three annual Caps) will be recalculated contingent on certain data updates. The Thresholds of the FB CRAC will also be adjusted to be the same as the Thresholds of the SN CRAC for the FB CRAC rates collected in FY 2004-2006, and the Thresholds for issuing a Rebate in those three years will be set to be $15 million above the SN CRAC Thresholds. In the Contingent Recalculation, BPA will change the parameters of the SN CRAC if there are:

1. Reductions in BPA's forecasted budgets for FY 2004-2006 for Internal Operations (sum of PBL Internal Operations and Corporate Internal Services);

2. Reductions in BPA's forecasted O&M budgets for FY 2004-2006 for the Columbia Generating Station;

3. Reductions in BPA's forecasted O&M budgets for FY 2004-2006 for the Corps of Engineers;

4. Reductions in BPA's forecasted O&M budgets for FY 2004-2006 for the Bureau of Reclamation;

5. Reductions in BPA's forecasted budgets for FY 2004-2006 for the BPA Fish and Wildlife Program;

6. Actual and forecasted changes in PBL's net revenue for FY 2003 due to changes in hydro conditions or market prices;

7. Negotiated reductions in the magnitude of benefits payments to be made by BPA to the Investor-Owned Utilities for FY 2004-2006.

The Recalculation of the SN CRAC parameters will meet the following standard:

The 2004 – 2006 three-year TPP must be at least 80 percent.

Procedure for Contingent Recalculation

1. Determining the Size of the Annual Caps

A preliminary calculation will be made using the FB CRAC Thresholds from the June 2001 Final Studies and data from the June 2003 Final Studies except for those items described above that are to be updated. This calculation will use three fixed (deterministic) SN CRAC revenue amounts that yield a three-year TPP of 80 percent and expected values of the sums of the FB CRAC and SN CRAC non-Slice rate impacts, expressed as a percentage of May 2000 base rates, that are the same for each of the three years[2].

The Caps for the SN CRAC will be set to be equal to the average of the three annual SN CRAC revenue amounts from Step 1, rounded to the nearest $5 million, plus $100 million.

2. **Synchronizing the SN CRAC, FB CRAC, and SN CRAC Rebate**

The thresholds for the FB CRAC will be set to be the same as the thresholds for the SN CRAC, and the thresholds for the SN CRAC Rebate will set to be $15 million higher than the SN CRAC threshold for each year.

3. **Calibrating the Thresholds**

The Thresholds for the SN CRAC will be adjusted until the 2004–2006 three-year TPP is 80 percent and the expected value of the sums of FB CRAC and SN CRAC non-Slice rate impacts, expressed as a percentage of May 2000 base rates, are the same for each of the three years.

F. Contingent Recalculation or Recalibration of SN CRAC Parameters due to Agreement among the IOUs, Public Agencies, and BPA regarding benefits payable to the IOUs during the 2004 through 2006 period.

The SN CRAC parameters and the Thresholds for the FB CRAC and the Rebate will be recalculated if the Administrator, in his sole determination, receives sufficient assurance, such as the signing by the IOUs of settlement contracts, that the benefits payable to the IOUs during 2004 through 2006 will be either reduced or deferred. The method by which such benefit reductions will be incorporated depends on the timing of the agreement.

1. **Agreement Reached Before Approximately August 15, 2003**

If an Agreement is reached with sufficient time before the Contingent Recalculation process described above, the cash

[2] The rate percentages are considered to be the same when rounded to one decimal point such that they have a total range of variation of no more than 0.1 percent. For example, three annual figures of 28.9, 28.8, and 28.9 would be acceptable, three annual figures of 28.7, 28.8, and 28.9 would not be.

impacts on BPA of the Agreement will be incorporated through the Contingent Recalculation.

2. **Agreement Reached After Approximately August 15, 2003, and by September 15, 2003**

If an Agreement is reached in this time period, a separate recalibration of the Thresholds for the SN CRAC, the FB CRAC, and the Rebate will be made. In this Recalibration, the cash impacts on BPA of the Agreement for FY 2004-2006 will be incorporated and the Thresholds adjusted following the Procedure for Contingent Recalculation described above. The 2003 ANR projection from the second August workshop will be used to recalculate the 2004 FB CRAC rate increases. The Administrator will release the revised rates on September 15, 2003, or as soon as practical thereafter, but no later than September 22, 2003.

3. **Agreement Reached After September 15, 2003, and by August 15, 2004, or After August 15, 2004, and by August 15, 2005**

If an agreement is reached in one of these time periods, the Thresholds for the SN CRAC, the FB CRAC, and the Rebate for the remaining year(s) of the SN CRAC rate period will be adjusted downward by the cumulative total of the cash impacts on BPA. For an agreement reached by August 15, 2004, the SN CRAC, FB CRAC, and Rebate Thresholds for 2005 will be reduced by the BPA cash impacts for FY 2005, and the Thresholds for 2006 will be reduced by the sum of the BPA cash impacts for FY 2005 and 2006; for an agreement reached by August 15, 2005, the SN CRAC, FB CRAC, and Rebate Thresholds for 2006 will be reduced by the BPA cash impacts for FY 2006. The Recalibrated Thresholds will be released to Parties at the first of the two workshops in August of 2004 or 2005.

4. **Conditions Occurring After September 15, 2003, and by August 15, 2004, or After August 15, 2004, and by August 15, 2005**

If conditions occur in one of these time periods that eliminate reductions or deferrals of benefits payable to the IOUs during 2004 through 2006, that have been used to recalibrate SN CRAC parameters, then the Thresholds for the SN CRAC, the FB CRAC, and the Rebate for the remaining year(s) of the SN CRAC rate period will be increased by the cumulative total of the cash impacts on BPA. For benefit reductions for conditions occurring by

August 15, 2004, the SN CRAC, FB CRAC and Rebate Thresholds for 2005 will be increased by the BPA cash impacts for FY 2005, and the Thresholds for 2006 will be increased by the sum of the BPA cash impacts for FY 2005 and 2006; for benefit reductions occurring after August 15, 2005, the SN CRAC, FB CRAC and Rebate Thresholds for 2006 will be increased by the BPA cash impacts for FY 2006. The Recalibrated Thresholds will be released to Parties in August of 2004 or 2005.

Part I: SN CRAC

2. Safety-Net Cost Recovery Adjustment Clause*

The SN CRAC applies to power purchases under the following firm power rate schedules:

- PF [Preference (excluding Slice), Exchange Program and Exchange Subscription];
- Industrial Firm Power (IP-02), [including purchases under the Industrial Firm Power Targeted Adjustment Charge (IPTAC) and Cost-Based Index Rate];
- Residential Load (RL-02) (including both actual power deliveries and the 900 aMW of monetary benefits under the financial portion of any REP Settlement, buy-downs and load reduction agreements);
- New Resource Firm Power (NR-02);
- Subscription purchases under Firm Power Products and Services (FPS).

The SN CRAC does not apply to:

- power purchases under Pre-Subscription contracts to the extent prohibited by such contracts;
- BPA's current contractual obligations for Seasonal and Irrigation Mitigation sales including for any eligible customer that converts from Slice to another BPA product;
- purchases under the PF Slice Rate.

A. Formula for Calculation of the Safety-Net Cost Recovery Adjustment Clause

The SN CRAC is an upward adjustment to the May 2000 rates for FY 2004-2006 that is calculated by a formula that compares PBL Accumulated Net Revenues (ANR) (as defined by the FB CRAC) to three annual Thresholds, and places caps on the amount of revenue that can be generated each year. It is additive to any LB CRAC or FB CRAC adjustments.

* Section II.F.3, Part I (SN CRAC) is reproduced with the section numbering from the 2003 Safety-Net Cost Recovery Adjustment Clause Final Proposal Administrator's Final Record of Decision Appendix A (SN-03-A-02) Page A-11, Section 2. Because of this, the numbering is not consistent throughout the GRSPs.

In August 2003, August 2004, and August 2005, a forecast of the Accumulated Net Revenue (ANR) through the end of that year will be completed. BPA will compare the forecasted ANR to the SN CRAC Threshold applicable to that year to determine the SN CRAC to be implemented. If the ANR at the end of the forecast year falls below the SN CRAC Threshold applicable to that fiscal year, an SN CRAC rate adjustment will be implemented. That SN CRAC rate adjustment will go into effect October 1 of the upcoming fiscal year (FY 2004-2006).

The Revenue Amount will be determined by the following formula:

> Revenue Amount is the lower of:
>
> SN CRAC Threshold minus (the sum of forecasted ANR plus the cumulative Cost Adjustment Limit plus Forecasted FB CRAC revenue for the fiscal year to which these calculations apply);
>
> and
>
> The annual Maximum Planned Recovery Amount, shown in Table B below.

Table B: SN CRAC & Rebate Parameters
[Dollars in Millions]

Applicability to Fiscal Year	ANR Calculated at end of Fiscal Year	SN CRAC Thresholds	Maximum Planned Recovery Amounts	Rebate Thresholds
2004	2003	-$378	$320	-$363
2005	2004	-$204	$320	-$189
2006	2005	-$161	$320	-$146

Where Revenue Amount is the amount of additional revenue that an adjustment in rates under SN CRAC is intended to generate during the one year period that the rate adjustment is effective.

Where SN CRAC Threshold is the ANR level below which a rate adjustment is determined. The Thresholds specified for the end of FY 2003, 2004, and 2005 are shown in Table B above.

Where ANR is generation function net revenues, as accumulated since 1999, at the end of each of the FY 2003-2005. The forecast of ANR through the end of each fiscal year will be calculated and used to determine if the Threshold has been reached and the Revenue Amount needed. Net revenues for any given fiscal year are accrued revenues less accrued expenses, in accordance with Generally Accepted Accounting Principles, with the following three exceptions. First, for purposes of determining if the SN CRAC Threshold has been reached, actual and forecasted expenses will include BPA expenses associated with Energy Northwest debt service as forecasted in the WP-02 Final Studies. Second, those actual and forecasted expenses will include BPA expenses associated with payments of benefits to the Investor-Owned Utilities as forecasted in the SN-03 Final Proposal.[3] Third, the impact of adopting Financial Accounting Standard 133, Accounting for Derivative Instruments and Hedging Activities, will not be considered in determining if the SN CRAC Threshold has been reached. Only generation function actual and forecasted revenues and expenses that are associated with the production, acquisition, marketing, and conservation of electric power, will be included in determinations under the SN CRAC. Accrued revenues and expenses of the transmission function are excluded. Impacts of forecasted revenues, positive or negative, from contractual true-up pursuant to the Slice Agreement shall be included in the revenue forecast when determining the SN CRAC.

Where Maximum Planned Recovery Amount is the maximum annual amount planned to be recovered through the SN CRAC.
Once the Revenue Amount is determined, that amount will be converted to the SN CRAC Percentage. The SN CRAC Percentage is the percentage adjustment in customers' rates (not including LB CRAC or FB CRAC) in each of the firm power rate schedules listed above. This percentage will be applied to generate the additional SN CRAC revenue.

The preliminary SN CRAC Percentage will be determined by the following formula:

SN CRAC Percentage =

Revenue Amount

Divided by

SN CRAC Revenue Basis

Where the SN CRAC Revenue Basis is the total generation revenue (not including LB CRAC or FB CRAC) for the loads subject to SN CRAC for the fiscal year in which the SN CRAC implementation begins, based on the then most current revenue forecast, (1) less any reductions due to

[3] This exclusion has been made so that the expense impact of any change to these benefits will not affect the annual calculation of the SN CRAC rate. (It would not be possible at the time of change, e.g., a settlement of the Public-IOU litigation, to be certain what the expense impacts would be; that could depend on an opinion of BPA's auditors which might not be rendered until several months after conclusion of such a settlement.) The impact on rates will be made through the Contingent Recalculation or the Recalibration of the SN CRAC parameters.

low density discount, and (2) less any IOU SN CRAC payments that create an obligation by BPA to make an off-setting payment under a contractual agreement based on the IOU SN CRAC payment.

Where the Forecasted Revenue Collection Amount will be calculated by applying the Preliminary SN CRAC Percentage to the forecast of revenues from products subject to the SN CRAC. This amount will vary from the Revenue Amount if the SN CRAC Percentage applicable to some customers is contractually limited. In this case, the SN CRAC Percentage will be set at the level that produces a Forecasted Revenue Collection Amount equal to the Revenue Amount.

Where the Cost Adjustment Limit is calculated annually for each year between FY 2003 and 2005 at the time of the SN CRAC calculation. It represents the amounts by which expenses in defined categories have exceeded the forecasted amounts in the SN-03 Final Study (SN-03-FS-BPA-01). *See* Table C. The Cost Adjustment Limit is the sum of the differences between each expense category as forecast in the appropriate Third Quarter Review and the forecast of those categories contained in the SN-03 Final Study, whenever the component differences are positive. If the Third Quarter Review forecast for any category is less than or equal to the forecast for that category from the SN-03 Final Study, the Cost Adjustment Limit component for that category will be $0.

Table C: Cost Adjustment Limits by Category
[Dollars in Millions]

PBL Expense Limits in Assessing SN CRAC FY 2003-2005
PBL Final Proposal ($ in thousands)

	EXPENSE LIMITS	Final Rate Case Update FY 2003 ($000)	Final Rate Case Update FY 2004 ($000)	Final Rate Case Update FY 2005 ($000)
1	PBL Internal Operations and Corporate Internal Services*	$ 105,813	$ 105,321	$ 107,426
2	Conservation Initiatives**	$ 19,278	$ 19,650	$ 19,650
3	Residential Exchange Financial Payment ***	$ 143,802	$ 143,802	$ 143,802
4	Corps and Reclamation O&M ****	$ 154,386	$ 164,800	$ 169,700
5	Other Generation Projects	$ 25,917	$ 31,346	$ 31,938
6	Renewable Projects	$ 24,702	$ 23,821	$ 48,654
7	Civil Service Retirement Payment	$ 17,600	$ 15,500	$ 13,300
8	**Total Expense Limits**	**$ 491,498**	**$ 504,240**	**$ 534,470**

** Does not include Slice implementation expenses*

***Does not include reimbursable contract expenses*

****Residential Exchange are the amounts of the 900 aMW of financial benefits provided under the financial portion of the REP settlement, excluding any payments by BPA to the IOUs repaying Residential Exchange expenses deferred by contract from a prior fiscal year.*

*****Does not include Fish & Wildlife related expenses*

In addition, the Cost Adjustment Limit for a fiscal year shall be adjusted to reflect any or all of the following situations. (1) If during that fiscal year, BPA experienced a *force majeure* condition which increases expenses in categories subject to the spending limits, the costs of such condition or conditions that are in the spending limit categories shall be subtracted from the value of the Cost Adjustment Limit. This Limit may be reduced to the extent that BPA has made reasonable efforts, in the Administrator's sole determination, to alleviate such *force majeure* conditions and mitigate the related increased expenses. For purposes of the General Rate Schedule Provisions, a *force majeure* condition shall be defined as: (a) court ordered legal judgments against BPA and settlements formally accepted by a court in connection with dismissal of litigation; (b) additional security or legal obligations imposed by statute, rule, or regulation; (c) regulatory requirements (including but not limited to Endangered Species Act implementation expenses) imposed by statute, rule, or regulation; and (d) natural or man-made disasters excluding BPA decisions that do not otherwise qualify as a *force majeure* condition. (2) If in fully allocating costs, certain "direct-charged" corporate expenses were moved between a category not considered in the Cost Adjustment Limit to one that is considered in the Cost Adjustment Limit, and there is no net increase in expenses charged to power rates, this cost shall be subtracted from the value of the Cost Adjustment Limit. (3) If there were any increase in the cost of administering the "Slice" program, this increase shall be subtracted from the value of the Cost Adjustment Limit. (4) If there were any increase in the cost allocated to power rates for the development and implementation of a Regional Transmission Organization, this increase shall be subtracted from the value of the Cost Adjustment Limit. (5) If there were any increase in cost due to increases in the market development reimbursables program that are fully offset by increased revenues, this increase will be subtracted from the value of the Cost Adjustment Limit. These adjustments will be made, as applicable, at the time the annual SN CRAC calculation is made. If after all the applicable adjustments listed above are made the value of the Cost Adjustment Limit is equal to or less than zero, the Cost Adjustment Limit shall be set equal to zero.

The Cumulative Cost Adjustment Limit for the FY 2004 SN CRAC (calculated late in FY 2003) is the FY 2003 Cost Adjustment Limit; the Cumulative Cost Adjustment Limit for the FY 2005 SN CRAC (calculated late in FY 2004) is the sum of the Cost Adjustment Limits for FY 2003 and 2004; the Cumulative Cost Adjustment Limit for the FY 2006 SN CRAC (calculated late in FY 2005) is the sum of the Cost Adjustment Limits for FY 2003 through 2005.

Each non-Slice product's total charge for energy, demand, and load variance will be adjusted by this SN CRAC percentage amount. Payment under the SN CRAC rate adjustment will be due monthly from November (for the October billing period) through October of the following year.

In August prior to the beginning of each fiscal year of the rate period (FY 2004-2006), the Administrator will compare the ANR forecast at the end of that current fiscal year to that year's SN CRAC Threshold. The customers will be billed in accordance with the SN CRAC adjustment.

Each customer will be notified, on or about September 1, of the percentage adjustment in rates due to the SN CRAC. The rates used to calculate the customers' bills for the following October through September for FY 2004-2006, will reflect the SN CRAC adjustment.

B. Contingent Recalculation of SN CRAC Parameters and Thresholds for FB CRAC and SN CRAC Rebate

In August 2003, the parameters of the SN CRAC (the three annual Thresholds and the three annual Caps) will be recalculated contingent on certain data updates. The Thresholds of the FB CRAC will also be adjusted to be the same as the Thresholds of the SN CRAC for the FB CRAC rates collected in FY 2004-2006, and the Thresholds for issuing a Rebate in those three years will be set to be $15 million above the SN CRAC Thresholds. In the Contingent Recalculation, BPA will change the parameters of the SN CRAC if there are:

1. Reductions in BPA's forecasted budgets for FY 2004-2006 for Internal Operations (sum of PBL Internal Operations and Corporate Internal Services);

2. Reductions in BPA's forecasted O&M budgets for FY 2004-2006 for the Columbia Generating Station;

3. Reductions in BPA's forecasted O&M budgets for FY 2004-2006 for the Corps of Engineers;

4. Reductions in BPA's forecasted O&M budgets for FY 2004-2006 for the Bureau of Reclamation;

5. Reductions in BPA's forecasted budgets for FY 2004-2006 for the BPA Fish and Wildlife Program;

6. Actual and forecasted changes in PBL's net revenue for FY 2003 due to changes in hydro conditions or market prices;

7. Negotiated reductions in the magnitude of benefits payments to be made by BPA to the Investor-Owned Utilities for FY 2004-2006.

The Recalculation of the SN CRAC parameters will meet the following standard:

The 2004 – 2006 three-year TPP must be at least 80 percent.

Procedure for Contingent Recalculation

1. **Determining the Size of the Annual Caps**

A preliminary calculation will be made using the FB CRAC Thresholds from the June 2001 Final Studies and data from the June 2003 Final Studies except for those items described above that are to be updated. This calculation will use three fixed (deterministic) SN CRAC revenue amounts that yield a three-year TPP of 80 percent and expected values of the sums of the FB CRAC and SN CRAC non-Slice rate impacts, expressed as a percentage of May 2000 base rates, that are the same for each of the three years[4].

The Caps for the SN CRAC will be set to be equal to the average of the three annual SN CRAC revenue amounts from Step 1, rounded to the nearest $5 million, plus $100 million.

2. **Synchronizing the SN CRAC, FB CRAC, and SN CRAC Rebate**

The thresholds for the FB CRAC will be set to be the same as the thresholds for the SN CRAC, and the thresholds for the SN CRAC Rebate will set to be $15 million higher than the SN CRAC threshold for each year.

3. **Calibrating the Thresholds**

The Thresholds for the SN CRAC will be adjusted until the 2004 – 2006 three-year TPP is 80 percent and the expected value of the sums of FB CRAC and SN CRAC non-Slice rate impacts, expressed as a percentage of May 2000 base rates, are the same for each of the three years.

C. Contingent Recalculation or Recalibration of SN CRAC Parameters due to Agreement among the IOUs, Public Agencies, and BPA regarding benefits payable to the IOUs during the 2004 through 2006 period.

The SN CRAC parameters and the Thresholds for the FB CRAC and the Rebate will be recalculated if the Administrator, in his sole determination, receives sufficient assurance, such as the signing by the IOUs of settlement contracts, that the benefits payable to the IOUs during 2004 through 2006 will be either reduced or deferred. The method by which such benefit reductions will be incorporated depends on the timing of the agreement.

1. **Agreement Reached Before Approximately August 15, 2003**

If an Agreement is reached with sufficient time before the Contingent Recalculation process described above, the cash impacts on BPA of the Agreement will be incorporated through the Contingent Recalculation.

[4] The rate percentages are considered to be the same when rounded to one decimal point such that they have a total range of variation of no more than 0.1 percent. For example, three annual figures of 28.9, 28.8, and 28.9 would be acceptable, three annual figures of 28.7, 28.8, and 28.9 would not be.

2. **Agreement Reached After Approximately August 15, 2003, and by September 15, 2003**

If an Agreement is reached in this time period, a separate recalibration of the Thresholds for the SN CRAC, the FB CRAC, and the Rebate will be made. In this Recalibration, the cash impacts on BPA of the Agreement for FY 2004-2006 will be incorporated and the Thresholds adjusted following the Methodology described above for use in the Contingent Recalculation. The 2003 ANR projection from the second August workshop will be used to recalculate the 2004 SN CRAC rate increases. The Administrator will release the revised rates on September 15, 2003, or as soon as practical thereafter, but no later than September 22, 2003.

3. **Agreement Reached After September 15, 2003, and by August 15, 2004, or After August 15, 2004, and by August 15, 2005**

If an agreement is reached in one of these time periods, the Thresholds for the SN CRAC, the FB CRAC, and the Rebate for the remaining year(s) of the SN CRAC rate period will be adjusted downward by the cumulative total of the cash impacts on BPA. For an agreement reached by August 15, 2004, the SN CRAC, FB CRAC, and Rebate Thresholds for 2005 will be reduced by the BPA cash impacts for FY 2005, and the Thresholds for 2006 will be reduced by the sum of the BPA cash impacts for FY 2005 and 2006; for an agreement reached by August 15, 2005, the SN CRAC, FB CRAC and Rebate Thresholds for 2006 will be reduced by the BPA cash impacts for FY 2006. The Cap(s) will be reduced by the change in cash flow for each year (not cumulative change in cash flow). The Recalibrated Thresholds will be released to Parties at the first of the two workshops described below in August of 2004 or 2005.

4. **Conditions Occurring After September 15, 2003, and by August 15, 2004, or After August 15, 2004, and by August 15, 2005**

If conditions occur in one of these time periods that eliminate reductions or deferrals of benefits payable to the IOUs during 2004 through 2006, that have been used to recalibrate SN CRAC parameters, then the Thresholds for the SN CRAC, the FB CRAC, and the Rebate for the remaining year(s) of the SN CRAC rate period will be increased by the cumulative total of the cash impacts on BPA. For benefit reductions for conditions occurring by

August 15, 2004, the SN CRAC, FB CRAC and Rebate Thresholds for 2005 will be increased by the BPA cash impacts for FY 2005, and the Thresholds for 2006 will be increased by the sum of the BPA cash impacts for FY 2005 and 2006; for benefit reductions occurring after August 15, 2005, the SN CRAC, FB CRAC and Rebate Thresholds for 2006 will be increased by the BPA cash impacts for FY 2006. The Cap(s) will be increased by the change in cash flow for each year (not cumulative change in cash flow). The Recalibrated Thresholds will be released to Parties at the first of the two workshops described below in August of 2004 or 2005.

D. Public Processes for the SN CRAC

Public Process in 2003 (for FY 2004)

In August 2003, BPA will begin a public process that will include two workshops. At the first workshop, held as soon as practical after completion of the Third Quarter Review, BPA will present the proposed contingent recalculation of the Thresholds for the FB and SN CRAC and the caps for the FB and SN CRAC. The estimated FB and SN CRAC revenue amounts and percentages for 2004 will also be presented. There will be a comment period of up to two weeks to allow time for interested parties to respond to BPA's analysis. BPA will announce the final FB and SN CRAC Thresholds and SN CRAC caps for the FB and SN CRACs applying to 2004 through 2006, and the final 2004 FB and SN CRAC rates at the second workshop with any adjustments accepted from feedback by interested parties. The final announcement of the rates for the next fiscal year will be on or about September 1. The Administrator may elect at his discretion, to reduce the SN CRAC rate adjustment. If the Administrator so elects, BPA will recalibrate the caps for the SN CRAC and the thresholds for FB CRAC and SN CRAC for later years to maintain the equivalent of the three year TPP of 80 percent. He shall then inform the customers of his decision during the workshops.

The sequence of the three stages of the calculations for both the first and second workshops are described below.

1. Contingent Recalculation Phase

In August of 2003, as soon as practical after completion of the Third Quarter Review, BPA will set the Thresholds for the FB and SN CRAC and caps for the SN CRAC as part of the Contingent Design. This analysis will set the ANR Thresholds and Caps for all three of the remaining years of the rate period (2004-2006) using the repayment standards as determined by the Administrator in the Final ROD. The FB

CRAC Thresholds will be the same as the SN CRAC Thresholds but the FB CRAC caps remain unchanged.

The items that will be reflected in the Contingent Design are shown in Table B above.

2. Variable Phase – FB CRAC Revenue And Percentages

Following the recalculation of the FB and SN CRAC Thresholds, a forecast of 2003 PBL ANR will be presented. The FB CRAC rate calculations, and the forecast of 2004 revenue generated by the FB CRAC, will be presented.

3. Variable Phase – SN CRAC Revenue And Percentages

The SN CRAC rate calculations will assume the revenue generated by the FB CRAC rate calculated in stage 2. The SN CRAC revenue amount will be the Threshold minus the sum of the ANR forecast and the forecast of 2004 FB CRAC revenue, or the annual cap, whichever is smaller. The SN CRAC rate percentage will be calculated so that the SN CRAC revenue amount is generated from the loads subject to the SN CRAC.

If an IOU-Publics settlement is reached after the last opportunity to include the settlement information in the Contingent Recalculation phase, approximately August 15, 2003, but before September 15, 2003, there will be a brief public process to announce the results of incorporating the settlement into the FB CRAC and SN CRAC results for FY 2004. The three steps above will be performed again with the same data except for data on the annual cashflows as modified by the settlement. The annual Caps for the SN CRAC and FB CRAC will not be changed. The Thresholds will be modified to meet the same repayment standards referred to in step 1. After that, first the FB CRAC for FY 2004 will be recalculated, and then the SN CRAC for FY 2004 will be recalculated.

Public Process in 2004 and 2005 (for FY 2005 and 2006)

In August of 2004 and 2005, BPA will begin a public process that will include two workshops. At the first workshop, BPA will present the final contingent rate design with the ANR forecast for the FB and SN CRAC and the estimated FB and SN CRAC percentages for FY 2005 and FY 2006 respectively. There will be up to a two-week comment period to allow time for customers to respond to BPA's analysis. BPA will announce the final rate at the second workshop with any adjustments accepted from customer feedback. The final announcement of the rates for the next fiscal year will be on or about September 1. The administrator may elect at his discretion, to reduce the SN CRAC rate adjustment. If the Administrator so elects, BPA will recalibrate the caps for the SN CRAC and the thresholds for FB CRAC and SN CRAC for later years to maintain the equivalent of the three-year TPP of 80 percent. He shall then inform the customers of his decision during the workshops.

E. Retriggering of the SN CRAC

The SN CRAC will be retriggered if the Administrator determines that, after implementation of the FB CRAC, the currently active SN CRAC, and any forecast of Augmentation True-Ups, either of the following conditions exists:

1. BPA forecasts a 50 percent or greater probability that it will nonetheless miss a payment to the U.S. Treasury or other creditor before the end of the then-current fiscal year, or

2. BPA has missed a payment to the U.S. Treasury or has satisfied its obligation to the U.S. Treasury but has missed a payment to any other creditor.

A retriggering of the SN CRAC will result in an upward adjustment to posted power rates listed above by modifying the SN CRAC parameters that are currently in use. BPA will propose changes to the SN CRAC parameters that will, to the extent market and other risk factors allow, achieve a high probability that the remainder of Treasury payments during the FY 2002-2006 rate period will be made in full. BPA's proposal could include changes to the Revenue Amount, the Cap, the Threshold, the duration (the length of time the SN CRAC would be in place, which could be more than one year), and the timing of collection. BPA may propose concomitant changes in the FB CRAC Thresholds. The additional revenue to be generated by the SN CRAC will be collected through a percentage adjustment in applicable rates and a commensurate decrease in the financial portion of the Residential Exchange Settlement. In addition to the revenue generated by the SN CRAC, BPA's payments for IOU load reductions will be reduced in accordance with contractual provisions.

a. SN CRAC Notification Process

At the time the Administrator determines that the SN CRAC has retriggered, BPA will send written notification of the determination to customers that purchase power under rates subject to the SN CRAC and to interested parties. Such notification shall include the documentation used by BPA to determine that the SN CRAC has retriggered, the amount of any forecast shortfall, and the time and location of a workshop on the SN CRAC.

The purpose of the SN CRAC workshop will be to discuss with customers and interested parties the cause of the shortfall, and any proposed changes to the SN CRAC that will achieve a high probability that the remainder of

Treasury payments during the FY 2002-2006 rate period will be made on time. In determining which proposal to include in its initial proposal in the SN CRAC Section 7(i) proceeding, BPA will give priority to prudent cost management and other options that enhance Treasury Payment Probability while minimizing changes to the SN CRAC.

b. SN CRAC Hearing Process

As soon as practicable after a determination that the SN CRAC has retriggered, BPA will publish a Federal Register Notice initiating an expedited hearing process to be conducted in accordance with Section 7(i) of the Northwest Power Act. The hearing shall be completed within 40 days, unless a different duration is agreed to by BPA and the parties. Upon completion of such hearing, BPA will submit the following documentation to FERC in support of a request for review and confirmation: Statements A through F from the 2002-2006 BPA Wholesale Power Rate Adjustment Proceedings, Separate Accounting Analyses, current and revised revenue tests, the proposed revisions to the SN CRAC parameters and the administrative record compiled by BPA in the SN CRAC proceeding.

The changes to the SN CRAC parameters shall take effect 60 days from filing with FERC unless FERC orders otherwise prior to that time.

Part II: SN CRAC Rebate

3. Safety-Net Cost Recovery Adjustment Clause Rebate (SNR)*

The SNR is a clause establishing criteria that the Administrator will use to decide whether funds are to be distributed to customers, and the amount that is to be distributed. The SNR enables BPA to distribute funds to eligible firm power customers and establishes the mechanism to be used to make a distribution.

The SNR applies to power purchases under the following firm power rate schedules, to the extent those purchasers were subject to the SN CRAC:

- PF [Preference (excluding Slice), Exchange Program and Exchange Subscription];
- Industrial Firm Power (IP-02), including purchases under the Industrial Firm Power Targeted Adjustment Charge (IPTAC) and Cost-Based Index Rate;
- Residential Load (RL-02) (including both actual power deliveries and the 900 aMW of monetary benefits under the financial portion of any REP Settlement, buy-downs and load reduction agreements);
- New Resource Firm Power (NR-02);

* Section II.F.3, Part II (SN CRAC) is reproduced with the section numbering from the 2003 Safety-Net Cost Recovery Adjustment Clause Final Proposal Administrator’s Final Record of Decision Appendix A (SN-03-A-02) Page A-23, Section 3. Because of this, the numbering is not consistent throughout the GRSPs.

- Subscription purchases under Firm Power Products and Services (FPS).

The SNR does not apply to:

- power purchases under Pre-Subscription contracts to the extent prohibited by such contracts;
- BPA's current contractual obligations for Seasonal and Irrigation Mitigation sales including for any eligible customer that converts from Slice to another BPA product;
- purchases under the PF Slice Rate.

A. Formula for the Calculation of the SNR Amount

The SNR, for FY 2005 and FY 2006, will be implemented if audited AANR for the end of any of the FY 2004-2005 are above the SNR Threshold value.

Where the AANR are generation function net revenues, as accumulated since 1999, at the end of each of FY 2004 and FY 2005. Net revenues are accrued revenues less accrued expenses, in accordance with Generally Accepted Accounting Principles, with the following three exceptions. First, for purposes of determining if the SN CRAC Threshold has been reached, actual and forecasted expenses will include BPA expenses associated with Energy Northwest debt service as forecasted in the WP-02 Final Studies. Second, those actual and forecasted expenses will include BPA expenses associated with payments of benefits to the Investor-Owned Utilities as forecasted in the SN-03 Final Studies.[5] Third, the impact of adopting Financial Accounting Standard 133, Accounting for Derivative Instruments and Hedging Activities, will not be considered in determining if the SN CRAC Threshold has been reached. Only generation function revenues and expenses, which is to say accrued revenues and accrued expenses that are associated with the production, acquisition, marketing, and conservation of electric power, are included in determinations under the SNR; accrued revenues and expenses of the transmission function are excluded. As part of BPA's annual audit process, BPA's independent outside auditing firm will confirm that BPA's ANR determination was consistent with applicable criteria. This confirmation will be made in accordance with additional agreed upon procedures established by BPA and its independent outside auditing firm after consultation with interested parties.

Where the SNR Threshold is the level of AANR that must be realized before a distribution is made as required by this section. The SNR Threshold is $15 million higher than the SN CRAC threshold for each of the two years to which the SNR applies.

[5] This exclusion has been made so that the expense impact of any change to these benefits will not affect the annual calculation of the SN CRAC rate. (It would not be possible at the time of change, e.g., a settlement of the Public-IOU litigation, to be certain what the expense impacts would be; that could depend on an opinion of BPA's auditors which might not be rendered until several months after conclusion of such a settlement.) The impact on rates will be made through the Contingent Recalculation or the Recalibration of the SN CRAC parameters.

Where the SNR Amount is 50 percent of the aggregate amount in excess of the SNR Threshold or the total amount of SN CRAC revenue BPA has booked, by the end of the previous fiscal year, less any previous Rebates, whichever is smaller. The SNR Amount may be equal to zero but not less than zero, and will be determined by the following formula:

SNR Amount = the smaller of

0.5 * (AANR - SNR Threshold, as adjusted),

and

Total SN CRAC revenue booked by the end of the previous fiscal year, less any previous Rebate.

If the SNR Amount is less than $5 million, no Rebate will be issued.

The Customer SNR Amount, which is the SNR Amount, will be returned to power customers. Any such amounts will be returned to customers in proportion to the SN CRAC Customer Revenue Amount, which is the revenue BPA received from each customer under rates subject to the SN CRAC since the beginning of the rate period, including SN CRAC revenues, or since the last SNR, whichever is later. A customer's SN CRAC Customer Revenue Amount excludes Slice revenues, and includes all non-Slice SN CRAC revenues. The IOU financial benefit is included as revenue based on the product of each customer's share of 900 aMW and the sum of the RL-02 rate and the amount of any SN CRAC applied to power deliveries under such rate.

Each customer's Customer Revenue Amount will be reduced by any amounts that would have been or are subjected to the SN CRAC but in which the SN CRAC revenues are offset, e.g., through a Low-Density Discount, or for reduction in deferrals or similar mechanism in an IOU Settlement should one occur.

SNR Percentage =

Each customer's SN CRAC Customer Revenue Amount

divided by

sum of all Customer Revenue Amounts

Each covered power customer will receive a Rebate equal to the Power Customer SNR Percentage times the Customer SNR Amount. One-twelfth of each customer's share of the Customer SNR Amount will be credited to customers, on bills for deliveries beginning April 1, and for FY 2005, remain in effect for

12 months, *i.e.*, through March 30 of the following year. In the last year of the rate period (FY 2006), one-sixth of each customer's share of the Customer SNR Amount will be credited to customers, on bills for deliveries beginning April 1, through September 30, 2006.

B. Determination of a Distribution

In January of each year of the rate period (FY 2005-2006), the Administrator will determine whether the AANR exceeds the SNR Threshold. If the AANR exceeds the SNR Threshold, customers and rate case parties will be notified. If the customer SNR amount is at least $5 million, the Administrator will provide by March 1, details of proposed distribution of the Customer SNR Amount. The Administrator will issue a final decision on the proposal on or about April 15.

C. Distribution Notification Process

BPA shall follow the following notification procedures:

a. **Financial Performance Status Reports**

By no later than August 31 of each year, BPA shall post on its electronic information access site (World Wide Web) a forecast of ANR attributable to the generation function for the FY ending September 30.

b. **Notice of SNR Trigger**

On or about January 15, in each of the FY 2005 and 2006, BPA will notify all power customers and rate case parties if the AANR exceeds the SNR Threshold. (If the December unaudited ANR report for the generation function indicated that the SNR Threshold might be exceeded, and the audited actuals show that it was not exceeded, customers will also be notified.)

(1) On or about February 15 in any year (FY 2005-2006) in which the AANR exceeds the SNR Threshold, the Administrator will notify all power customers and rate case parties. Notification will include the AANR for the prior fiscal year, the SNR Amount, the calculation of any adjustments to the threshold, calculation of the SNR Amount, the sum of Customer Revenue Amounts, and each customer's proposed SNR percentage. The notice shall also describe the data and assumptions relied upon by BPA. Such data, assumptions, and documentation, if non-proprietary and/or non-privileged, shall be made available for review at BPA upon request. The notice shall also contain the tentative schedule for the remainder of the SNR implementation process.

Prior to March 15, BPA will conduct a public review and comment process on the SNR proposal.

(2) On or about April 15, in any year (FY 2005-2006) in which the AANR exceeds the SNR Threshold, BPA shall notify customers to which the SNR applies of the decision on the proposal, the final calculation of the SNR Amount, and the sums of the customer revenue amounts.

D. Contingent Recalculation of SN CRAC Parameters and Thresholds for FB CRAC and SN CRAC Rebate

In August 2003, the parameters of the SN CRAC (the three annual Thresholds and the three annual caps) will be recalculated contingent on certain data updates. The Thresholds of the FB CRAC will also be adjusted to be the same as the Thresholds of the SN CRAC for the FB CRAC rates collected in FY 2004-2006, and the Thresholds for issuing a Rebate in those three years will be set to be $15 million above the SN CRAC Thresholds. In the Contingent Recalculation, BPA will change the parameters of the SN CRAC if there are:

1. Reductions in BPA's forecasted budgets for FY 2004-2006 for Internal Operations (sum of PBL Internal Operations and Corporate Internal Services);

2. Reductions in BPA's forecasted O&M budgets for FY 2004-2006 for the Columbia Generating Station;

3. Reductions in BPA's forecasted O&M budgets for FY 2004-2006 for the Corps of Engineers;

4. Reductions in BPA's forecasted O&M budgets for FY 2004-2006 for the Bureau of Reclamation;

5. Reductions in BPA's forecasted budgets for FY 2004-2006 for the BPA Fish and Wildlife Program;

6. Actual and forecasted changes in PBL's net revenue for FY 2003 due to changes in hydro conditions or market prices;

7. Negotiated reductions in the magnitude of benefits payments to be made by BPA to the Investor-Owned Utilities for FY 2004-2006.

The Recalculation of the SN CRAC parameters will meet the following standard:

The 2004 – 2006 three-year TPP must be at least 80 percent.

Procedure for Contingent Recalculation

1. **Determining the Size of the Annual Caps**

   A preliminary calculation will be made using the FB CRAC Thresholds from the June 2001 Final Studies and data from the June 2003 Final Studies except for those items described above that are to be updated. This calculation will use three fixed (deterministic) SN CRAC revenue amounts that yield a three-year TPP of 80 percent and expected values of the sums of the FB CRAC and SN CRAC non-Slice rate impacts, expressed as a percentage of May 2000 base rates, that are the same for each of the three years[6].

   The Caps for the SN CRAC will be set to be equal to the average of the three annual SN CRAC revenue amounts from Step 1, rounded to the nearest $5 million, plus $100 million.

2. **Synchronizing the SN CRAC, FB CRAC, and SN CRAC Rebate**

   The thresholds for the FB CRAC will be set to be the same as the thresholds for the SN CRAC, and the thresholds for the SN CRAC Rebate will set to be $15 million higher than the SN CRAC threshold for each year.

3. **Calibrating the Thresholds**

   The Thresholds for the SN CRAC will be adjusted until the 2004 – 2006 three-year TPP is 80 percent and the expected value of the sums of FB CRAC and SN CRAC non-Slice rate impacts, expressed as a percentage of May 2000 base rates, are the same for each of the three years.

E. Contingent Recalculation or Recalibration of SN CRAC Parameters due to Agreement among the IOUs, Public Agencies, and BPA regarding benefits payable to the IOUs during the 2004 through 2006 period.

The SN CRAC parameters and the Thresholds for the FB CRAC and the Rebate will be recalculated if the Administrator, in his sole determination, receives sufficient assurance, such as the signing by the IOUs of settlement contracts, that the benefits payable to the IOUs during 2004 through 2006 will be either reduced or deferred. The method by which such benefit reductions will be incorporated depends on the timing of the agreement.

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[6] The rate percentages are considered to be the same when rounded to one decimal point such that they have a total range of variation of no more than 0.1 percent. For example, three annual figures of 28.9, 28.8, and 28.9 would be acceptable, three annual figures of 28.7, 28.8, and 28.9 would not be.

1. **Agreement reached before approximately August 15, 2003**

   If an Agreement is reached with sufficient time before the Contingent Recalculation process described above, the cash impacts on BPA of the Agreement will be incorporated through the Contingent Recalculation.

2. **Agreement Reached After Approximately August 15, 2003, and by September 15, 2003**

   If an Agreement is reached in this time period, a separate recalibration of the Thresholds for the SN CRAC, the FB CRAC, and the Rebate will be made. In this Recalibration, the cash impacts on BPA of the Agreement for FY 2004-2006 will be incorporated and the Thresholds adjusted following the Methodology described above for use in the Contingent Recalculation. The 2003 ANR projection from the second August workshop will be used to recalculate the 2004 SN CRAC rate increases. The Administrator will release the revised rates on September 15, 2003, or as soon as practical thereafter, but no later than September 22, 2003.

3. **Agreement Reached After September 15, 2003, and by August 15, 2004, or After August 15, 2004, and by August 15, 2005**

   If an agreement is reached in one of these time periods, the Thresholds for the SN CRAC, the FB CRAC, and the Rebate for the remaining year(s) of the SN CRAC rate period will be adjusted downward by the cumulative total of the cash impacts on BPA. For an agreement reached by August 15, 2004, the SN CRAC, FB CRAC and Rebate Thresholds for 2005 will be reduced by the BPA cash impacts for FY 2005, and the Thresholds for 2006 will be reduced by the sum of the BPA cash impacts for FY 2005 and 2006; for an agreement reached by August 15, 2005, the SN CRAC, FB CRAC and Rebate Thresholds for 2006 will be reduced by the BPA cash impacts for FY 2006. The Recalibrated Thresholds will be released to Parties in August of 2004 or 2005.

4. **Conditions Occurring After September 15, 2003, and by August 15, 2004, or After August 15, 2004, and by August 15, 2005**

   If conditions occur in one of these time periods that eliminate reductions or deferrals of benefits payable to the IOUs during 2004 through 2006, that have been used to recalibrate SN CRAC parameters, then the Thresholds for the SN CRAC, the FB CRAC, and the Rebate for the remaining year(s) of the SN CRAC rate period will be increased by the cumulative total of the cash impacts on BPA. For benefit reductions for conditions occurring by August 15, 2004, the SN CRAC, FB CRAC and Rebate Thresholds for 2005 will be increased by the BPA cash impacts for FY 2005, and the Thresholds for 2006 will be increased by the sum of the BPA cash impacts for FY 2005 and 2006; for benefit reductions occurring after August 15, 2005, the SN CRAC, FB CRAC and Rebate Thresholds for 2006 will be increased by the BPA cash impacts for FY 2006. The Recalibrated Thresholds will be released to Parties in August of 2004 or 2005.

G. Demand Adjuster

The Demand Adjuster is applied to a customer's demand billing factor. It is a number less than or equal to one calculated by dividing the customer's Total Retail Load on the GSP by the customer's Total Retail Load on their system peak. The minimum Demand Adjuster is 0.6 six tenths. The Demand Adjuster is used with the demand billing factor for the Actual Partial Service Products, and with the demand billing factor for the Block with Factoring.

H. 4. Dividend Distribution Clause*

The DDC is a clause establishing criteria that the Administrator will use to decide whether funds are to be distributed to customers, and the amount that is to be distributed. The DDC enables BPA to distribute funds to eligible firm power customers and establishes the mechanism to be used to make a distribution.

The DDC applies to purchases by power customers under these firm power rate schedules subject to the FB CRAC, including:

- PF [Preference (excluding Slice), Exchange Program, and Exchange Subscription];
- Industrial Firm Power (IP-02), including under the Industrial Firm Power Targeted Adjustment Charge (IPTAC) and Cost-Based Index Rate;
- Residential Load (RL-02);
- New Resource Firm Power (NR-02);
- purchases under Firm Power Products and Services (FPS) that are subject to the FB CRAC;
- the financial portion of the REP Settlement as described herein.

The DDC does not apply to power purchases under Pre-Subscription contracts, or purchases under the Slice Rate.

1. Formula for the Calculation of the Dividend Distribution Amount

The DDC, for FY 2003-2006, will be implemented if audited AANR for the end of any of the FY 2002-2005 are above the DDC Threshold value. DDC calculations will be made after SN CRAC Rebate calculations in those years in which a Rebate is possible (FY 2005 and 2006).

* Section II.H (DDC) is reproduced with the section numbering from the 2003 Safety-Net Cost Recovery Adjustment Clause Final Proposal Administrator's Final Record of Decision Appendix A (SN-03-A-02) Page A-31, Section 4. Because of this, the numbering is not consistent throughout the GRSPs.

AANR are generation function net revenues, as accumulated since 1999, at the end of each of the FY 2002-2005. Net revenues are accrued revenues less accrued expenses, in accordance with Generally Accepted Accounting Principles, with the following three exceptions. First, for purposes of determining if the SN CRAC Threshold has been reached, actual and forecasted expenses will include BPA expenses associated with Energy Northwest debt service as forecasted in the WP-02 Final Studies. Second, those actual and forecasted expenses will include BPA expenses associated with payments of benefits to the Investor-Owned Utilities as forecasted in the SN-03 Final Studies.[7] Third, the impact of adopting Financial Accounting Standard 133, Accounting for Derivative Instruments and Hedging Activities, will not be considered in determining if the DDC threshold has been reached. Only generation function revenues and expenses, which is to say accrued revenues and accrued expenses that are associated with the production, acquisition, marketing, and conservation of electric power, are included in determinations under the DDC; accrued revenues and expenses of the transmission function are excluded. As part of BPA's annual audit process, BPA's independent outside auditing firm will confirm that BPA's AANR determination was consistent with applicable criteria. This confirmation will be made in accordance with additional agreed-upon procedures established by BPA and its independent outside auditing firm after consultation with interested parties.

DDC Threshold is the level of AANR that must be realized before a distribution is made as required by this section. The DDC Threshold is $993 million for the end of FY 2002, $735 million for the end of FY 2003, and $401 million for the end of FY 2004 and 2005.

The DDC threshold for any fiscal year will be adjusted upward by the following:

a. In the event that there has been a power system emergency (as defined in "FCRPS Protocols for Emergency Operation In Response to Generation or Transmission Emergencies" dated September 22, 2000, or replacement protocols) during the fiscal year; and BPA has agreed to provide additional funding to mitigate the impact of the emergency operations on fish and wildlife, any of the additional emergency-related fish and wildlife funding which BPA has not spent during that fiscal year will be added to the threshold amount for that year; and/or

b. In the event that BPA fish and wildlife operations and maintenance ("direct program") costs previously budgeted for expenditure in that fiscal

[7] This exclusion has been made so that the expense impact of any change to these benefits will not affect the annual calculation of the SN CRAC rate. (It would not be possible at the time of change, e.g., a settlement of the Public-IOU litigation, to be certain what the expense impacts would be; that could depend on an opinion of BPA's auditors which might not be rendered until several months after conclusion of such a settlement.) The impact on rates will be made through the Contingent Recalculation or the Recalibration of the SN CRAC parameters.

year were not spent, but for which a need continues, they will be added to the threshold amount for that year.

DDC Amount is the aggregate amount in excess of the DDC Threshold that is available to be distributed to customers. Amounts already scheduled to be distributed via the SN CRAC Rebate will be deducted from this aggregate excess before distributing the DDC. The DDC Amount may be equal to zero and will be determined by the following formula:

DDC Amount =

AANR – the sum of the DDC Threshold, as adjusted, and any amount to be Rebated for the same year.

The first $15 million of the DDC Amount, if the DDC Amount exceeds $15 million, or the entire DDC Amount if it equals $15 million or less, will be allocated to qualifying customers participating in the C&R Discount. The C&R Discount is a rate mechanism designed to encourage incremental conservation and renewable resource development by BPA's power purchasers under PF, IP, RL, and NR rate schedules. *See* C&R Discount GRSPs, Section II.A (2002 Wholesale Power Rate Schedules, GRSPs, Revised December 2001).

The Customer DDC Amount, which is the DDC Amount after reduction by the $15 million as described in the preceding paragraph, will be returned to power customers. Any such amounts will be returned to customers in proportion to the DDC Customer Revenue Amount, which is the revenue BPA received from each customer under rates subject to the DDC since the beginning of the rate period, or since the last DDC, whichever is later. A customer's DDC Customer Revenue Amount excludes Slice revenues, and includes all non-Slice CRAC revenues. The IOU financial benefit is included as revenue based on the product of each customer's share of 900 aMW and the sum of the RL-02 rate and the amount of any CRAC applied to power deliveries under such rate.

DDC Percentage =

Each customer's DDC Customer Revenue Amount

divided by

sum of all Customer Revenue Amounts

Each covered power customer will receive a Rebate equal to the Power Customer DDC Percentage times the Customer DDC Amount. One-twelfth of each customer's share of the Customer DDC Amount will be credited to customers, on bills for deliveries beginning April 1, and for any FY 2003-2005, remain in effect for 12 months, *i.e.*, through March 30 of the following year. In the last year of the rate period (FY 2006), one-sixth of each customer's share of the Customer DDC Amount will be credited to customers, on bills for deliveries beginning April 1, through September 30, 2006.

2. Determination of a Distribution

In January of each year of the rate period (FY 2003-2006), the Administrator will determine whether the AANR exceeds the DDC Threshold. If the AANR exceeds the DDC Threshold, customers and rate case parties will be so notified. By March 1, the Administrator will provide calculations of any proposed distribution of Customer DDC Amount. The Administrator will issue a final decision on the proposal on or about April 15.

3. Distribution Notification Process

BPA shall follow the following notification procedures:

a. **Financial Performance Status Reports**

By no later than August 31 of each year, BPA shall post on its electronic information access site (World Wide Web) a forecast of AANR attributable to the generation function for the fiscal year ending September 30.

b. **Notice of DDC Trigger**

On or about January 15, in each of the FY 2003-2006, BPA will notify all power customers and rate case parties if the AANR exceeds the DDC Threshold. (If the December unaudited AANR report for the generation function indicated that the DDC Threshold might be exceeded, and the audited actuals show that it was not exceeded, customers will also be notified.)

(1) On or about February 15, of any of FY 2003-2006 in which the AANR exceeds the DDC Threshold, the Administrator will notify all power customers and rate case parties. Notification will include the AANR for the prior fiscal year, the DDC Amount, the calculation of any adjustments to the threshold, calculation of the DDC Amount, the sum of Customer Revenue Amounts, and each customer's proposed DDC percentage. The notice shall also describe the data and assumptions relied upon by BPA. Such data, assumptions, and documentation, if non-proprietary and/or non-privileged, shall be made available for review at BPA upon

request. The notice shall also contain the tentative schedule for the remainder of the DDC implementation process.

Prior to March 15, BPA will conduct a public review and comment process on the proposal.

(2) On or about April 15, of any of the FY 2003-2006 in which the AANR exceeds the DDC Threshold, BPA shall notify customers to which the DDC applies of the decision on the proposal, the final calculation of the DDC Amount, the allocation of the DDC Amount, and, if applicable, the resulting level of the Power Customer DDC Percentage to be applied to each applicable firm power rate schedule.

I. Excess Factoring Charges

1. Excess Within-Day Factoring Charge

The within-day factoring test compares the hour-by-hour shape of the customer's load to the customer's hour-by-hour energy take from BPA within a day. This test identifies whether or not the hour-by-hour shape of the customer's take from BPA has used more within-day factoring service, measured in kWh, than the underlying load would have used.

Excess Within-Day Factoring Charge, for any hour(s) in the month, applies to amount of hourly energy in excess of the authorized maximum energy amounts defined by the customer's within-day load shape.

The total amount of Excess Within-Day Factoring Charge during the HLHs of the month shall be billed the greater of:

a. Five (5) mills/kWh;

b. Among all HLH periods of the billing month, the maximum within-day difference between the highest hourly HLH California Independent System Operator (ISO) Supplemental Energy price (NP15) and the lowest hourly HLH California ISO Supplemental Energy price (NP15).

The total amount of Excess Within-Day Factoring Charge during the LLHs of the month shall be billed the greater of:

a. Five (5) mills/kWh;

b. Among all LLH periods of the billing month, the maximum within-day difference between the highest hourly LLH California ISO Supplemental

Energy price (NP15) and the lowest hourly LLH California ISO Supplemental Energy price (NP15).

In the event that the index for ISO Supplemental Energy expires, that index will be replaced for the purpose of deriving Excess Within-Day Factoring Charges by another hourly energy index, such as the California Power Exchange (CalPX) (NW1 or NW 3), at a hub at which Northwest parties can trade.

2. Excess Within-Month Factoring Charges

The within-month factoring test compares the day-by-day shape of the customer's load to the customer's day-to-day energy take from BPA within a month. This test identifies whether the day-to-day shape of the customer's take from BPA used more within-month factoring service than the underlying load would have used. The within-day factoring test (see above) is not equipped to identify a factoring service issue if, for example, the customer resource deliveries were zero for a particular day. The within-month factoring test is equipped to address that type of instance. The within-month factoring test establishes an upper and lower boundary for each diurnal period of the day. Excess within-month factoring for each diurnal period is the greater of: (1) the sum of the amounts greater than the upper boundary; or (2) the sum of the amounts less than the lower boundary.

Excess Within-Month Factoring Charge applies to that amount of energy take that either exceeds or falls short of a range defined by: (1) a flat load placement on BPA; and (2) a load placement that follows the customer's actual load shape.

The Excess Within-Month Factoring quantities are reduced by any Unauthorized Increase Energy amounts in the like diurnal period, and only the residual is charged the Excess Within-Month Factoring Charge.

The Excess Within-Month Factoring during the HLHs of the month shall be billed the greater of:

a. Five (5) mills/kWh.

b. The highest peak Dow Jones (DJ) Mid-Columbia (Mid-C) Index price for firm power during the month LESS the lowest peak DJ Mid-C Firm Index price for firm power during the month.

c. The highest average HLH California ISO Supplemental Energy price (NP15) (average of hours 7 through 22, excluding Sundays) during the month LESS the lowest average HLH California ISO Supplemental Energy price (NP15) for the same period.

The Excess Within-Month Factoring during the LLHs of the month shall be billed the greater of:

a. Five (5) mills/kWh.

b. The highest offpeak DJ Mid-C Index price for firm power during the month LESS the lowest offpeak DJ Mid-C Index price for firm power;

c. The highest average LLH California ISO Supplemental Energy price (NP15) (average of hours 1 through 6, and 23, and 24 Monday through Saturday; average of hours 1 through 24 Sunday) during the month LESS the lowest average LLH California ISO Supplemental Energy price (NP15) for the same month in the same time period.

The DJ Mid-C Index definitions for HLHs (or Peak) and LLHs (or offpeak) will be adjusted, as necessary, to be consistent with (comport with) BPA's definition for HLH and LLH periods.

In the event that the index for ISO Supplemental Energy or DJ Mid-C Index expires, that index will be replaced for the purpose of deriving Excess Within-Month Factoring Charges by another hourly or diurnal energy index, such as the CalPX (NW1 or NW3), at a hub at which Northwest parties can trade.

J. Five-Year Flat Block Price Forecast

The Five-Year Flat Block Price Forecast is BPA's price estimate of the market price for five-year block purchases for the FY 2002-2006 period. This forecast is used in calculating the cash component of the settlements of the REP with regional IOUs as described in BPA's Power Subscription Strategy. The Five-Year Flat Block Price Forecast for this purpose is $38 per MWh.

K. Flexible Industrial Firm Power (IP) Rate Option

The Flexible IP rate option will be offered at BPA's discretion to purchasers who make a contractual commitment to purchase under this option for all five years of the rate period. The charges and billing factors under this option will be specified by BPA at the time the Administrator offers to make power available to a Purchaser under this option.
The actual charges and billing factors will be mutually agreed to by BPA and the Purchaser subject to satisfying the following condition:

Equivalent NPV Revenues: Forecasted revenues from a Purchaser under the Flexible IP rate option must be equivalent, on a net present value basis, to the revenues BPA would have received had the appropriate charges specified in the IP rate schedule Section II been applied to the same sales.

The Flexible IP rate contract may establish a limit on the amount of power purchased at the Flexible IP rate. In this case, purchases beyond the contractual limit will be billed at the Demand and Energy charges specified in the IP rate schedule Section II unless such power would be charged as an Unauthorized Increase.

Risk Adjustments: Credit risk associated with individual customers will be a factor in establishing any flexible rate option. Creditworthiness will be determined by BPA consistent with prevailing business standards, and applied consistently to each customer. Such credit risks will be dealt with through a "margin deposit," expense charge, built into the rates, or other methods acceptable to BPA.

L. Flexible New Resource Firm Power (NR) Rate Option

The Flexible NR rate option will be offered at BPA's discretion to purchasers who make a contractual commitment to purchase under this option. The charges and billing factors under this option shall be specified by BPA at the time the Administrator offers to make power available to a Purchaser under this option. The customers purchasing under the Flexible NR rate option purchase the same set of power products and services that they would otherwise purchase under the rate schedule. The actual charges and billing factors will be mutually agreed to by BPA and the Purchaser subject to satisfying the following condition:

Equivalent NPV Revenues: Forecasted revenues from a Purchaser under the Flexible NR rate option must be equivalent, on a net present value basis, to the revenues BPA would have received had the appropriate charges specified in the NR rate schedule Section II been applied to the same sales.

The Flexible NR rate contract may establish a limit on the amount of power purchased at the Flexible NR rate. In this case, purchases beyond the contractual limit will be billed at the Demand and Energy (and Load Variance and Stepped-Up Multiyear Block (SUMY), if appropriate) charges specified in the PF rate schedule Section II, unless such power would be charged as an Unauthorized Increase.

M. Flexible Priority Firm Power (PF) Rate Option

The Flexible PF rate option will be offered at BPA's discretion to purchasers who make a contractual commitment to purchase under this option. The charges and billing factors under this option shall be specified by BPA at the time the Administrator offers to make power available to a Purchaser under this option. The customers purchasing under the Flexible PF rate option purchase the same set of power products and services that they would otherwise purchase under the rate schedule. The actual charges and billing factors will be mutually agreed to by BPA and the Purchaser subject to satisfying the following condition:

Equivalent NPV Revenues: Forecasted revenues from a Purchaser under the Flexible PF rate option must be equivalent, on a net present value basis, to the revenues BPA would have received had the appropriate charges specified in the PF rate schedule Section II been applied to the same sales.

The Flexible PF rate contract may establish a limit on the amount of power purchased at the Flexible PF rate. In this case, purchases beyond the contractual limit will be billed at the Demand and Energy, (and Load Variance and SUMY, if appropriate) charges specified in the PF rate schedule Section II, unless such power would be charged as an Unauthorized Increase.

N. Green Energy Premium

1. Overview of the Premium

The Green Energy Premium (GEP) is a premium ranging from zero to $40/MWh that a customer elects to pay BPA to ensure that BPA is producing some system power from Environmentally Preferred Power (EPP) resources. The GEP is the difference between the customer's applicable average annual energy charge under the PF-02, RL-02, NR-02, and IP-02 rates and the total cost of the EPP resource selected by the customer. The GEP is applied to the number of EPP MWh that the customer has elected to purchase. BPA guarantees the customer paying the premium that BPA will produce an amount of EPP equal to the amount of energy subject to this adjustment. The GEP will be charged in a line item on the monthly power bill of each participating customer.

The costs to be considered in determining the applicable GEP include, but are not limited to:

- Costs of existing EPP resources, over and above the cost of BPA system resources.
- Costs of new EPP resources, over and above the cost of BPA system resources.
- Costs of BPA system resources.
- Endorsement fees for specific EPP resources.
- Market purchases of EPP resources.
- Transmission and other services required to integrate EPP resources into the BPA system.

2. Calculation and Application of the Premium

a. Determination of the Premium

For a customer buying power from BPA under a requirements firm power sales contract, the amount of EPP and the GEP will be determined as part of the product selection process and will be completed as part of the power sales contract negotiation. The charge will not exceed $40 per MWh and may be as low as zero. The premium will be zero if the unit cost of the GEP resource(s) dedicated to the customer is equal to, or less than, the energy charge of the applicable rate. The GEP will recover the average unit cost of the EPP resource(s) minus the applicable average PF-02, RL-02, NR-02, and IP-02 energy charge over the term of the purchase.

b. Determination of Individual Customer GEP

(1) Customers will be provided notice of the availability of specific GEP products and associated premiums. The total GEP for the customer will be based on the customer's elections of product amounts and content.

(2) The average annual energy charge will be calculated as the average per kWh charge for an annual flat undelivered product using the energy charges applicable to the customer. Where customers are purchasing under more than one rate schedule, the average energy charge will be calculated using expected loads and applicable rate schedules.

(3) The individual customer GEP for billing will be the total cost of the product selected by the customer minus the average annual energy charge.

c. Application of the GEP

The GEP will be applied after BPA has determined all other charges and credits except the C&R Discount line item, on the participating customer's power bill.

d. Billing for the Premium

The customer's bill will include a line item showing the kWh amount of EPP purchased times the GEP for the products elected and the total cost. The calculation will appear as:

(EPP amount) kWh * GEP mills/kWh = $XXXXX

O. Guaranteed Delivery Charge (Nonfirm only)

A surcharge of 2.00 mills/kWh of Billing Energy is applied whenever BPA guarantees delivery of nonfirm energy to a Purchaser under the Nonfirm Energy (NF) Standard rate or Market Expansion rate.

P. Industrial Firm Power Targeted Adjustment Charge (IPTAC)

1. Availability

The IPTAC pertains to the IP rate schedule. The IPTAC will be applied to Firm Power requirements service of DSIs who take service from a combination of Federal inventory and power purchased from the market during the 2002 rate period.

The maximum total requirements service the IPTAC will be developed for, and applied to, is 1,440 average megawatts (aMW) (flat, annual block). The total inventory used to provide this requirement service will be composed of 990 aMW from Federal inventory and 450 aMW of market purchases.

There will be two rates for the IPTAC product. 1,210 aMW will be sold at \$23.50 per MWh, and 230 aMW sold at \$25 per MWh.

Q. Low Density Discount (LDD)

1. Application and Definitions

For eligible Purchasers as defined in section 2 below, a discount shall be applied each billing month to BPA's charges for the following components of the PF Preference rate, the PF Exchange Program rate, and the NR-02 rate: (1) Demand; (2) HLH purchases; (3) LLH purchases; and (4) Load Variance. The Low Density Discount (LDD) shall not be applied to Unauthorized Increase Charges, Excess Factoring Charges, transmission charges or any other charges. The discount shall be revised annually based on data supplied by June 30 of each Calendar Year (CY) for the previous CY and shall become effective on the upcoming October 1.

a. The Kilowatthour/Investment Ratio

The kWh/Investment (K/I) ratio is calculated annually based on the data supplied by June 30 for the previous CY. The K/I ratio is calculated by dividing the Purchaser's Total Retail Load during the CY by the value of the Purchaser's depreciated electric plant (excluding generation plant) at the end of the CY.

b. **The Consumers/Mile of Line Ratio**

The Consumers/Mile of Line (C/M) ratio is determined annually using the data supplied by June 30 for the previous CY. The C/M ratio is calculated by dividing the maximum number of consumers within the distribution system, in any one month during the CY, by the end of CY number of pole miles of distribution.

Consumer means every billed consumer regardless of usage. Separately billed services for water heating and security lights are not counted as an additional billed consumer.

The number of pole miles of distribution line means the end of CY pole miles. Distribution lines are defined as lines that deliver electric energy from a substation or metering point, at a voltage of 34.5 kilovolt (kV) or less, to the point of attachment to the consumer's wiring and include primary, secondary, and service facilities. (Service drops are considered service facilities.)

These calculations shall be based on CY data provided from the Purchaser's annual financial and operating reports. The Purchaser shall certify that the data submitted is correct and that no loads gained as provided in section 6, Retail Access Exclusion, are receiving LDD benefits.

In calculating these ratios, BPA shall compile the data submitted by the Purchaser based on the Purchasers entire electric utility system in the PNW. For Purchasers with service territories that include any areas outside the PNW, BPA shall compile data submitted by the Purchaser separately on the Purchaser's system in the PNW and on the Purchaser's entire electric utility inside and outside the PNW. BPA will apply the eligibility criteria and discount percentages to the Purchaser's system within the PNW and, where applicable, also to its entire system inside and outside the PNW. The Purchaser's eligibility for the LDD will be determined by the lesser amount of discount applicable to its PNW system or to its combined system inside and outside the PNW. BPA, in its sole discretion, may waive the requirement to submit separate data for the Purchaser with a small amount of its system outside the PNW. Results of the calculations shall not be rounded.

A Purchaser who has not provided BPA with the requisite pieces of data needed to calculate the K/I and C/M ratios by June 30 of each year, for the prior CY, shall be declared ineligible for the LDD, effective the upcoming October 1.

If a Purchaser's data was submitted on time and a revision is necessary to the data, the revised data must be resubmitted no later than 12 months after the original submission date to be considered for an adjustment.

2. Eligibility Criteria

To qualify for a discount, the Purchaser must meet all five of the following eligibility criteria:

a. the Purchaser must serve as an electric utility offering power for resale;

b. the Purchaser must agree to pass the benefits of the discount through to the Purchaser's eligible consumers within the region served by BPA;

c. the Purchaser's average retail rate for the reporting year must exceed the Purchaser's average cost of BPA power purchases under the applicable rate for the qualifying period by at least 10 percent. For CY 2001, the Purchaser's average cost of BPA power purchases under the applicable rate shall be under the applicable 1996 rate for the first nine months and under the applicable 2002 rate for the last three months. For CY 2002 and beyond, the Purchaser's average cost of BPA power purchases under the applicable rate shall be under the applicable rate for all 12 months;

d. the Purchaser's K/I ratio must be less than 100; and

e. the Purchaser's C/M ratio must be less than 12.

3. Discounts

The Purchaser shall be awarded the following discount beginning October 1, 2001, in accordance with section 4 below. The discount will be the sum of the two potential discounts for which the Purchaser qualifies, based on the following Table C. The discount shall not exceed 7 percent.

Table C
LDD Percentage Discount Table

Percentage Discount	*Applicable Range for kWh/Investment (K/I) Ratio*	*Applicable Range for Consumers/Mile (C/M) Ratio*
0.0%	$35.0 \leq X$	$12.0 \leq X$
0.5%	$31.5 \leq X < 35.0$	$10.8 \leq X < 12.0$
1.0%	$28.0 \leq X < 31.5$	$9.6 \leq X < 10.8$
1.5%	$24.5 \leq X < 28.0$	$8.4 \leq X < 9.6$
2.0%	$21.0 \leq X < 24.5$	$7.2 \leq X < 8.4$
2.5%	$17.5 \leq X < 21.0$	$6.0 \leq X < 7.2$
3.0%	$14.0 \leq X < 17.5$	$4.8 \leq X < 6.0$
3.5%	$10.5 \leq X < 14.0$	$3.6 \leq X < 4.8$
4.0%	$7.0 \leq X < 10.5$	$2.4 \leq X < 3.6$

Percentage Discount	***Applicable Range for kWh/Investment (K/I) Ratio***	***Applicable Range for Consumers/Mile (C/M) Ratio***
4.5%	$3.5 \le X < 7.0$	$1.2 \le X < 2.4$
5.0%	$X \le 3.5$	$X < 1.2$

4. LDD Phase-Out Adjustment

If the Purchaser satisfies the eligibility criteria (2. a. through e.), and the calculated discount differs from the existing discount by more than one-half of 1 percent, the applicable discount will be:

a. the existing discount plus one-half percent if the calculated discount exceeds the existing discount; or

b. the existing discount minus one-half percent if the calculated discount is less than the existing discount.

The foregoing formula will be applied each October 1 until the then-current calculated discount is fully phased out.

The Purchaser is not eligible to receive any discount, effective each October, if the Purchaser fails to meet the eligibility criteria in section 2. a. through e.

5. Additional Adjustment for Very Low Densities

If a Purchaser’s C/M ratio is 3 or less and its K/I ratio is 26 or less, after determination of the discount pursuant to sections 3 and 4 above, an additional one-half percent shall be added to the Purchaser’s discount, but the total discount shall not exceed 7 percent. In subsequent years, the one-half percent added to the discount pursuant to this section shall not be included when determining the applicable discount in section 4 above.

6. Retail Access Exclusion

Load that is gained by a Purchaser as a direct result of retail access rights established by Federal, state, or local legislation, and that would not otherwise have been gained absent such legislation, is not eligible to receive the benefits provided by the LDD. The Purchaser shall not pass the benefits of the LDD to its gained load consumers.

7. Application of the LDD to Slice

To be eligible for the LDD, customers that purchase the Slice product must meet the eligibility criteria under section 2.

The LDD benefit for Slice customers will be determined and applied as follows:

By September of each year, BPA will establish a dollars/MWh discount rate for each one-half percent discount bracket, from 0.5 percent to 7 percent. The dollars/MWh discount rate for each bracket will be determined by using billing data of customers within the same non-Slice LDD percentage bracket. Those customers' total dollars in non-Slice LDD discounts they received will be divided by the total eligible MWh purchased. This will result in a dollars/MWh rate that can then be used as the yearly/monthly discount for a Slice customer that is eligible, under section 3, to receive the same discount. BPA will use billing data from the previous CY from the non-Slice LDD recipients when calculating the dollars/MWh discount rate for Slice product recipients. When there are no non-Slice LDD recipients available in a given discount bracket to calculate the $/MWh value, it is appropriate to determine a linear relationship using a regression analysis to arrive at a $/MWh value for that bracket. When there is an increase or decrease in the PF rate for HLH and LLH billing determinants, not due to the Targeted Adjustment Charge (TAC), SN CRAC, FB CRAC, or the DDC, the regional average increase or decrease will be applied to the $/MWh rate that coincides with the increase or decrease rate(s) for the non-Slice LDD recipients for the same period.

The rate will only be applied to that portion of Slice power being purchased that is requirements power. This quantity is defined in the Slice Contract as Critical Slice Amount. The annual Slice true up will include an LDD true-up if based on estimates. If it is based on after-the-fact monthly data, no true-up is necessary.

R. Rate Melding

BPA's rate proposal allows the customers more than one rate choice. Separately tracking and administering the customers rate choices and maintaining the distinction would increase BPA's overall cost of providing rate choices. For administrative simplicity upon mutual agreement between BPA and the customer, BPA may offer to meld the customer's rate choices into a single composite set of rates that reflects the specific choices made by the customer. BPA will ensure that this melded set of rates will result in a bill that is nearly mathematically equivalent to applying the customer's individual choices throughout the rate period. BPA will provide the affected customer the calculations it used to establish the melded rates and provide 30 days for the customer to review and accept the melding calculation before it implements the melded rates. Melded rates established by BPA will continue until one of the customer's rate choices expires, or a rate adjustment occurs that is provided for under the chosen rate schedules (*e.g.,* CRAC), or a significant change in the loads applicable to the rates occurs.

S. Slice True-Up Adjustment

Each year BPA will calculate the financial true-up for the previous fiscal year, in accordance with the provisions of the Slice Agreement. This contractual true-up will be completed each year regardless of whether the LB CRAC has increased or decreased the PF Slice Rate. See the Slice Product Costing and True-Up Table (Table D). The revenues from this contractual true-up will not be included in any calculation, or application, of the LB CRAC. In addition, adjustments to the Slice rate contained in Administrator's Record of Decision in 2002 Final Power Rate Proposal, WP-02-A-02, May 2000, that occur in accordance with the methodology in section F of these GRSPs are separate, and are applied separately from, the financial true-up under the Slice Agreement referred to in this paragraph.

T. Stepped-Up Multiyear Block (SUMY)

The SUMY Block charge applies to Block purchases if the annual amounts increase (*i.e.*, step up) over multiple years of a purchase commitment term due to increases in customer net requirement which are not subject to a TAC.

The cost for the SUMY Block service is the difference between PF-02 rates and the AURORA On and Offpeak market price forecast in the final rate proposal.

The starting basis for computing the SUMY Block quantities will be the purchaser's subscribed block amount for the period October 2001 through September 2002. Costs will be computed for 24 monthly blocks (12 HLH and 12 LLH) for each year of the rate period. Each year's monthly amount above the base year's monthly amount is the stepped-up quantity. Total cost is the sum of each month's HLH and LLH stepped-up quantities times each month's HLH and LLH costs.

The SUMY charge is the total cost of the SUMY Block service divided by the total Block energy purchase including stepped-up amounts. The charge is in addition to the PF and NR energy and demand rates that the customer will pay for these power purchases.

Formula for Calculating a Charge for SUMY Block Service:

Step 1: Determine HLH MWh of SUMY Block.
October 2002 HLH Block minus October 2001 HLH Block = HLH MWh of SUMY Block for October 2002

Step 2: Determine LLH MWh of SUMY Block.
October 2002 LLH Block minus October 2001 LLH Block = LLH MWh of SUMY Block for October 2002

Table D

	SLICE PRODUCT COSTING AND TRUE-UP TABLE							
			A	B	C	D	E	F
1	PBL Costs ($000)	2002-2006	2002	2003	2004	2005	2006	TOTAL
2	**GENERATION COSTS**	**Audited**	**Projected**					
3	Federal Base System	**Actuals**						
4	Hydro							
5	Upstream benefits		$ 1,990	$ 2,050	$ 2,111	$ 2,174	$ 2,240	$ 10,565
6	Corps of Engineers O&M		$ 108,000	$ 112,000	$ 112,000	$ 112,000	$ 112,000	$ 556,000
7	Corps Depreciation		$ 73,329	$ 75,497	$ 78,292	$ 81,258	$ 83,620	$ 391,996
8	U.S. Fish & Wildlife O&M		$ 15,400	$ 16,197	$ 16,995	$ 17,892	$ 18,789	$ 85,273
9	Bureau of Reclamation O&M		$ 47,000	$ 48,300	$ 48,300	$ 48,300	$ 48,300	$ 240,200
10	Bureau Depreciation		$ 19,470	$ 20,043	$ 20,535	$ 21,009	$ 21,516	$ 102,573
11	Colville Settlement		$ 16,000	$ 16,000	$ 16,000	$ 16,000	$ 16,000	$ 80,000
12	Packwood Dam		$ 2,343	$ 2,577	$ 2,835	$ 3,118	$ 3,430	$ 14,301
13	Net Interest Expense		$ 157,914	$ 158,579	$ 166,657	$ 176,226	$ 177,170	$ 836,546
14	**Subtotal**		**$ 441,446**	**$ 451,243**	**$ 463,724**	**$ 477,977**	**$ 483,065**	**$ 2,317,455**
15	Fish and Wildlife							
16	Expense		$ 131,700	$ 138,000	$ 140,100	$ 142,900	$ 144,400	$ 697,100
17	Amortization		$ 19,772	$ 21,842	$ 23,737	$ 25,394	$ 26,407	$ 117,152
18	Net Interest Expense		$ 6,540	$ 6,759	$ 7,181	$ 7,259	$ 7,166	$ 34,905
19	**Subtotal**		**$ 158,012**	**$ 166,601**	**$ 171,018**	**$ 175,553**	**$ 177,973**	**$ 849,157**
20	Trojan							
21	Decommissioning		$ 9,600	$ 4,200	$ 2,600	$ 2,600	$ 2,600	$ 21,600
22	Debt Service		$ 9,947	$ 9,954	$ 9,964	$ 9,989	$ 10,009	$ 49,863
23	**Subtotal**		**$ 19,547**	**$ 14,154**	**$ 12,564**	**$ 12,589**	**$ 12,609**	**$ 71,463**
24	WNP #1							
25	O&M		$ 400	$ 384	$ 384	$ 384	$ 384	$ 1,936
26	Debt Service		$ 177,704	$ 167,856	$ 174,623	$ 167,910	$ 179,992	$ 868,085
27	**Subtotal**		**$ 178,104**	**$ 168,240**	**$ 175,007**	**$ 168,294**	**$ 180,376**	**$ 870,021**
28	WNP #2							
29	O&M/Capital Requirements		$ 154,094	$ 163,824	$ 170,724	$ 173,824	$ 179,824	$ 842,290
30	Debt Service		$ 197,442	$ 244,980	$ 233,624	$ 187,825	$ 211,976	$ 1,075,847
31	**Subtotal**		**$ 351,536**	**$ 408,804**	**$ 404,348**	**$ 361,649**	**$ 391,800**	**$ 1,918,137**
32	WNP #3							
33	Debt Service		$ 153,720	$ 152,993	$ 149,232	$ 149,480	$ 147,836	$ 753,261
34	**Total**		**$ 1,302,364**	**$ 1,362,035**	**$ 1,375,894**	**$ 1,345,542**	**$ 1,393,659**	**$ 6,779,494**
35								
36	New Resources							
37	Idaho Falls		$ 3,740	$ 3,737	$ 3,744	$ 3,754	$ 3,754	$ 18,729
38	Cowlitz		$ 14,914	$ 14,987	$ 15,051	$ 15,123	$ 15,196	$ 75,271
39	Firm Purchased Power		$ 17,723	$ 17,953	$ 18,187	$ 18,435	$ 18,681	$ 90,978
40	Competitive Acquisitions		$ 12,158	$ 12,340	$ 12,526	$ 12,713	$ 12,904	$ 62,642
41	Columbia Hills (CARES)		$ 4,323	$ 4,359	$ 4,397	$ 4,446	$ 4,490	$ 22,015
42	Wheeling Power Purchase		$ 1,242	$ 1,253	$ 1,264	$ 1,275	$ 1,287	$ 6,321
43	Other Acquisitions		$ -	$ -	$ -	$ -	$ -	$ -
44	**Total**		**$ 36,377**	**$ 36,677**	**$ 36,982**	**$ 37,312**	**$ 37,631**	**$ 184,978**
45								
46	Legacy Conservation							
47	Conservation expense		$ 18,201	$ 16,613	$ 16,913	$ 17,313	$ 17,613	$ 86,651
48	Generation Billing Credits		$ 7,934	$ 7,898	$ 7,866	$ 7,834	$ 7,785	$ 39,317
49	Conservation Financing		$ 5,578	$ 5,577	$ 5,577	$ 5,577	$ 5,577	$ 27,886
50	Conservation Amortization		$ 59,337	$ 55,586	$ 47,125	$ 43,179	$ 37,650	$ 242,877
51	Conservation Interest		$ 38,822	$ 39,345	$ 35,237	$ 34,779	$ 32,001	$ 180,184
52	**Subtotal**		**$ 129,872**	**$ 125,019**	**$ 112,718**	**$ 108,681**	**$ 100,626**	**$ 576,915**
53	Energy Services Business		$ 11,663	$ 11,690	$ 11,601	$ 11,475	$ 11,444	$ 57,873
54	Other Generation Costs							
55	BPA Programs							
56	CSRS Pension Expense		$ 27,600	$ 17,550	$ 15,450	$ 13,250	$ 11,600	$ 85,450
57	Power Marketing		$ 16,000	$ 15,700	$ 8,800	$ 6,800	$ 5,000	$ 52,300
58	Power Scheduling		$ 20,900	$ 12,800	$ 12,100	$ 12,800	$ 12,700	$ 71,300
59	Inventory Solution Hedging Activities		$ -	$ -	$ -	$ -	$ -	$ -
60	Generation Oversight		$ 2,964	$ 2,950	$ 3,050	$ 3,050	$ 3,150	$ 15,163
61	Administrative & Support Services		$ 17,350	$ 16,650	$ 16,650	$ 16,650	$ 16,650	$ 83,950
62	Power Planning Council		$ 5,100	$ 5,100	$ 5,100	$ 5,100	$ 5,100	$ 25,500
63	Miscellaneous Depreciation		$ 4,296	$ 4,693	$ 4,383	$ 3,411	$ 2,973	$ 19,756
64	Geothermal Demonstration		$ 15,768	$ 15,768	$ 15,768	$ 15,768	$ 15,768	$ 78,840
65	Renewables		$ 3,091	$ 2,870	$ 2,683	$ 2,551	$ 2,459	$ 13,654
66	Contingency Resources		$ 391	$ 369	$ 317	$ 395	$ 342	$ 1,814
67	Net Interest Expense		$ 406	$ 359	$ 325	$ 312	$ 308	$ 1,710
68	Between Business Line Expense		$ 4,000	$ 4,000	$ 4,000	$ 4,000	$ 4,000	$ 20,000
69	Other							
70	WNP #3 Plant		$ 3,086	$ 3,169	$ 3,169	$ 3,169	$ 3,169	$ 15,762
71	**Total Other Generation Costs**		**$ 120,952**	**$ 101,978**	**$ 91,795**	**$ 87,256**	**$ 83,218**	**$ 485,199**
72	**Minimum Required Net Revenues**		$ -	$ -	$ -	$ -	$ -	$ -
73	**COSA Table Subtotal**		**$ 1,601,227**	**$ 1,637,398**	**$ 1,628,989**	**$ 1,590,266**	**$ 1,626,578**	**$ 8,084,458**

Table D (Continued)

			A	B	C	D	E		F
	PBL Costs ($000)	2002-2006	2002	2003	2004	2005	2006		TOTAL
		Audited	Projected						
74		Actuals							
75	Net Residential Exchange Costs		$ -	$ -	$ -	$ -	$ -		$ -
76	Subscription Settlement Costs (900 aMW's in $)		$ 69,725	$ 69,725	$ 69,725	$ 69,725	$ 69,725		$ 348,626
77									
78	Slice Initial Implementation Expenses		$ -	Not applicable	Not applicable	Not applicable	Not applicable		$ -
79	Slice Implementation Expenses		$ -	$ -	$ -	$ -	$ -		$ -
80									
81	CEA Transmission Costs		$ 13,514	$ 17,105	$ 26,685	$ 26,685	$ 26,685		$ 110,675
82	Ancillary and Reserve Service Costs		$ 10,000	$ 10,000	$ 8,000	$ 8,000	$ 8,000		$ 44,000
83	PBL PF Trans. Pass-Through Costs		$ -	$ -	$ -	$ -	$ -		$ -
84	PNCA & NTS Transmission Costs		$ 1,815	$ 1,815	$ 1,815	$ 1,815	$ 1,815		$ 9,075
85	General Transfer Agreement Costs		$ 47,200	$ 47,200	$ 47,200	$ 47,200	$ 47,200		$ 236,000
86									
87	**REVENUE REQUIREMENT CHECK**		**$ 1,743,482**	**$ 1,783,243**	**$ 1,782,414**	**$ 1,743,692**	**$ 1,780,003**	**0**	**$ 8,832,833**
88									
89	PF Conservation and Renewables Credit Costs								$ 95,104
90	IP Conservation and Renewables Credit Costs								$ 31,536
91	RL Conservation and Renewables Credit Costs								$ 21,900
92	LDD		$ 14,000	$ 14,000	$ 14,000	$ 14,000	$ 14,000		$ 70,000
93	S & I Rate Mitigation Costs		$ 4,000	$ 4,000	$ 4,000	$ 4,000	$ 4,000		$ 20,000
94	**Non-COSA Table Subtotal**								$ 238,540
95									
96	**Total PBL Revenue Requirement**								**$ 9,071,373**
97									
98	**Revenue Credits ($000)**								
99	Ancillary and Reserve Service Revs.		$ 80,380	$ 80,293	$ 81,127	$ 81,098	$ 81,025		$ 403,924
100	PBL PF Trans. Pass-Through Revs.		$ -	$ -	$ -	$ -	$ -		$ -
101	Canadian Entitlement Credit		$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000		$ 5,000
102									
103	COE & USBR Project Revenues		$ 8,100	$ 8,100	$ 8,100	$ 8,100	$ 8,100		$ 40,500
104	4(h)(10)(c)		$ 88,147	$ 91,007	$ 90,731	$ 92,873	$ 95,177		$ 457,935
105	Colville Credit		$ 4,600	$ 4,600	$ 4,600	$ 4,600	$ 4,600		$ 23,000
106	FCCF		$ 51,406	$ 33,261	$ 22,681	$ 16,079	$ 6,899		$ 130,326
107	Sup/Ent Cap; Irr. Pump		$ 938	$ 707	$ 471	$ 471	$ 471		$ 3,059
108	Energy Efficiency Revenues		$ 13,046	$ 13,345	$ 13,345	$ 13,345	$ 13,345		$ 66,426
109	Property Trnfrs & Misc.		$ 3,416	$ 3,416	$ 3,416	$ 3,416	$ 3,416		$ 17,080
110									
111	**Total Revenue Credits**								**$ 1,147,249**
112									
113	**Power Revenues Needed**								**$ 7,924,124**
114									
115	Firm System Augmentation (1282 aMWs on average)		$ 322,218	$ 336,766	$ 289,159	$ 323,744	$ 306,070		$ 1,577,958
116	DSI Augmentation (450 aMWs)		$ 113,888	$ 113,888	$ 113,888	$ 113,888	$ 113,888		$ 569,442
117	Conservation Augmentation (20,40,60,80,100 aMW)		$ 5,415	$ 10,831	$ 16,246	$ 21,662	$ 27,077		$ 81,231
118	**Total Cost of Inventory Solution**		**$ 441,522**	**$ 461,485**	**$ 419,294**	**$ 459,294**	**$ 447,036**		**$ 2,228,632**
120									
121	Revenue 1282 aMWs flat, 450 aMWs to DSIs		$ (327,235)	$ (327,235)	$ (327,235)	$ (327,235)	$ (327,235)		$ (1,636,175)
122	**Net Cost of Inventory Solution**		**$ 114,287**	**$ 134,250**	**$ 92,059**	**$ 132,060**	**$ 119,801**		**$ 592,457**
123									
124		($000)							
125	**Annual Slice Revenue Requirement**	**$ 1,703,316**							
126	**Monthly Slice Revenue Requirement**	**$ 141,943**				**Five Year Total**			**$ 8,516,581**
127	**One Percent of Monthly Requirement**	**$ 1,419.43**							
128									

Step 3: Determine Cost of HLH SUMY Block service.
HLH MWh of SUMY Block * (Aurora October 2002 On-Peak Market Price minus October 2002 PF HLH energy and demand rate) = Total Cost of October 2002 HLH SUMY Block service.

Step 4: Determine Cost of LLH SUMY Block service.
LLH MWh of SUMY Block * (Aurora October 2002 Off-Peak Market Price minus October 2002 PF LLH energy rate) = Total Cost of October 2002 LLH SUMY Block service.

Step 5: Determine Cost for all months of the rate period by repeating Steps 1-4 for each month of the remaining purchase period always calculating the MWh difference from the first year and corresponding month. Calculate the price difference using that year's and month's market price and PF rate.

Step 6: Custom Charge: Divide the Net Present Value (NPV) of the stream of costs derived from Steps 1-5 by the NPV of the total block purchase including SUMY Block in MWh for the five-year period. The NPV uses a 6.8 percent discount rate and is present valued to October 2001.

Step 7: Billing Determinant: Custom charge is applied to each MWh of block purchase including the SUMY Block amounts.

U. Supplemental Contingency Reserves Adjustment (SCRA)

The energy charges stated in the IP-02 rate schedule will be adjusted to reflect the negotiated SCRA adjustment. PBL will negotiate with any DSI interested in providing Supplemental Contingency Reserves (Supplemental Reserves). Supplemental Reserves refers to generating capacity, and associated energy, fully available within 10 minutes notice of a system disturbance. PBL has established a flexible rate with a cap that will permit BPA to negotiate a price according to the quality of reserves provided.
The maximum amount PBL may pay for Supplemental Reserves from a DSI is capped at $5.63/kW-mo.

The suitability and quality of the Supplemental Reserves will be measured by whether they have certain characteristics, some of which are required and others optional. Any Supplemental Reserves purchased by PBL must be consistent with North American Electric Reliability Council (NERC), Western Systems Coordinating Council (WSCC), and Northwest Power Pool (NWPP) criteria:

1. the interruptible load must be offline within five minutes after a call by BPA;

2. in the event of a system disturbance, the interruptible load must be accessible prior to a request for reserves from other NWPP parties; and

3. the interruptible load must be available to be offline for up to 60 minutes.

In addition to these required characteristics, the issues identified below will help define when PBL may pay the maximum value for Supplemental Reserves:

1. the extent to which PBL has the discretion when and how to use all operating reserves and to determine what resources to call on in the event of a system disturbance; and

2. whether there are limitations on the number of times or total minutes the reserves may be utilized.

V. Targeted Adjustment Charge (TAC)

1. Availability

The TAC pertains to the PF rate schedule, except for PF exchange program and PF Exchange Subscription rates. The TAC also applies to purchases under the NR rate. The TAC applies to firm power requirements service to regional firm load that results in an unanticipated increase in BPA's projected loads within the rate period. The TAC will be applied to the applicable rate for requirements service requested after the Subscription window closes. TAC also applies to customers that add load through retail access after the window closes including load that was once served and returns under retail access.

TAC will also apply to subsequent requests made by a customer under a Subscription contract for requirements service for such customer's load(s) that had been previously served by that customer's 5(b)(1)(A) or 5(b)(1)(B) resources. The TAC will not apply to purchases included in a customer's initial Subscription contract.

If a public agency customer that requests requirements service from BPA is annexing or otherwise taking on the obligation of load from another public agency customer and the request to annex or take on load obligation and the reduction in obligation are equal amounts such that BPA's total load obligation does not increase, BPA may exempt the newly acquired load from the TAC and apply PF-02. The TAC will apply if the annexed requirements service has been previously served by that customer's 5(b)(1)(A) or 5(b)(1)(B) resources.

Where a public agency customer annexes residential and small farm load previously served by an IOU and such load was receiving BPA power or financial benefits through Subscription, the public agency customer will receive by assignment through BPA the right to the IOUs power and/or financial benefits applicable to the annexed load. BPA will deliver an amount of firm power to the annexing public agency customer at the PF-02 rate equal to the amount of benefit (power and/or financial) assigned by the IOU to BPA. Power provided by BPA to the public agency customer to meet the remaining annexed load not covered by the benefits assigned from the IOU will be subject to the TAC.

The TAC will apply for the duration of the Customer's contract or until 2006, whichever occurs first. For five-year contracts that guarantee rates for multiple periods (for example, contracts that have both three- and five-year components) the TAC applies until the end of the five-year rate period. If a new public requests service, the TAC, if any, must apply until 2006.

If a customer is serving a portion of its load with a certifiable renewable resource eligible for the C&R Discount, or contract purchases of certified renewable resource power eligible for the C&R Discount for a period less than the term of the customer's BPA requirements firm power contract, then the customer may request, during the 2002 to 2006 rate period, requirements firm power service for such load at the end of the specified contract period at PF Preference (PF-02) without being subject to the TAC. This limited exception applies to the first 200 aMW in any contract year, or to amounts that BPA specifies in accordance with its Policy on the Determination of Net Requirements.

2. Energy Charge

The TAC is a monthly mills/kWh adjustment to the HLH and LLH energy rates specified in the 2002 rate schedule, and is applied to that portion of the Purchaser's load that is subject to the TAC. The TAC rate adjustment will be established based on the following formula:

TAC = [(Incr $ * Incr Amt) – (Rate $ * Incr Amt)]/TAC Amt

where:

TAC Amt	=	The amount of load subject to the TAC, determined monthly.
Rate $	=	The monthly PF (or NR) energy rate shown in the applicable rate schedule.
Inventory Amt	=	Amount of energy in inventory available to serve this load based on average annual Federal system firm resource capability, estimated using critical water excluding balancing purchases and purchases for system augmentation, from the 2002 rate case with updates if BPA determines that is necessary.

Incr $ = Monthly cost to BPA, including a handling fee, of incremental power purchases expressed in mills/kWh. These costs also may include, where applicable, wheeling, ancillary, and other charges BPA may incur in purchasing power from other entities such as, but not limited to, the California ISO or the CalPX.

Incr Amt = Amount of incremental power required, determined monthly and defined as the TAC Amt minus the Inventory Amt. (If there is no available Inventory Amt, the Incr Amt will equal the TAC Amt).

If Incr $ is less than Rate $, the TAC is 0 mills/kWh.

TAC is the monthly rate adjustment in mills/kWh.

BPA will calculate the cost (Incr $) per month in mills/kWh of the additional power per month (Incr Amt) for a specific customer request. BPA will establish the cost of the additional power by the following methods:

- BPA will establish the price based on BPA's monthly cost to purchase the incremental load by purchases of resources at market.

W. Unauthorized Increase Charge

1. Charge for Unauthorized Increase in Demand

The amount of Measured Demand during a billing hour that exceeds the amount of demand the purchaser is contractually entitled to take during that hour shall be billed at the greater of:

a. Three (3) times the applicable monthly demand charge;

b. The sum of hourly California ISO Spinning Reserve Capacity prices for all HLHs in the month, at path NW1 (COB); or

c. The sum of hourly California ISO Spinning Reserve Capacity prices for all HLHs in the month, at path NW3 Nevada-Oregon Border (NOB).

In the event that the hourly California ISO Spinning Reserve Capacity market expires, the Unauthorized Increase Charge for demand shall be the greater of:

a. Three (3) times the applicable monthly demand charge;

b. the sum of hourly or diurnal prices for all HLHs in the month, at a hub at which Northwest parties can trade, established between October 1, 2001, and September 30, 2006.

2. Charge for Unauthorized Increase in Energy

The amount of Measured Energy during a diurnal period of a billing month, day, or hour that exceeds the amount of energy the purchaser is contractually entitled to take during that period shall be billed the greater of:

a. One hundred (100) mills/kWh; or

b. for the month in question, the greater of:

(1) the highest diurnal DJ Mid-C Index price for firm power; or

(2) the highest hourly ISO California Supplemental Energy price (NP15).

The DJ Mid-C Index definitions for HLHs (or peak) and LLHs (or offpeak) will be adjusted, as necessary, to be consistent with (comport with) BPA's definitions for HLH and LLH periods.

In the event that either the ISO California Supplemental Energy price index or the DJ Mid-C Index expires, the index will be replaced for purposes of the Unauthorized Increase Charge for energy by:

(1) the highest price experienced for the month at the CalPX, NW1 (COB);

(2) the highest price experienced for the month at the CalPX, NW3 (NOB); or

(3) the highest price experienced for the month from any applicable new hourly or diurnal energy index at a hub at which Northwest parties can trade, established between October 1, 2001, and September 30, 2006.

X. Slice Portion of IOU Settlement

Each monthly Slice bill will include a line item to account for the proposed increment in the IOU cash settlement above the May Proposal. The revenues from this section will not be included in any calculation of the LB CRAC.

The monthly adjustment per one-percent Slice is proposed to be:
[Incremental amount of IOU Settlement costs in the Supplemental Rate Case ROD/12/100] = $ per month per one-percent Slice.
The incremental amount of IOU Settlement costs = [($38.00/MWh-$28.10/MWh) x (900 aMW x 8,760 hours)]/12/100
= $78,051,600/12/100
= $65,043 per month per one-percent Slice

SECTION III. DEFINITIONS

A. Power Products and Services Offered By the Power Business Line of BPA

1. Actual Partial Service Product – Simple/Complex

The Actual Partial Service Products are core Subscription products that are available to purchasers who have a right to purchase from BPA for their requirements. These products are intended for customers who have contractual or generating resources with firm capabilities and therefore require a product other than Full Service. The Simple and Complex versions of this product category differ in that the Complex version is subject to the Factoring Benchmark tests in the billing process and to potential Excess Factoring Charges. The Simple version encompasses several possible approaches to customer resource declaration, all of which obviate the need for the Factoring Benchmark tests.

2. Block Product

The Block Product is a core Subscription product that is available to purchasers who have a right to purchase from BPA for their requirements. This product is available in HLH and LLH quantities per month, with the hourly amount flat for all hours in such periods.

3. Block Product with Factoring

The Block Product with Factoring is a combination of the Block Product with the core Subscription staple-on product for Factoring Service. Factoring provides the service of distributing Block energy to follow Purchaser hourly load needs to the extent of such Block energy.

4. Block Product with Shaping Capacity

The Block Product with Shaping Capacity is a combination of the Block HLH energy product and the core Subscription staple-on product for Shaping capacity. Shaping capacity allows the customer to preschedule Block energy with some limited shape among HLHs within a contractually specified bandwidth.

5. Construction, Test and Start-Up, and Station Service

Power for the purpose of Construction, Test and Start-Up, and Station Service for a generating resource or transmission facility shall be made available to eligible purchasers under the Priority Firm Power (PF-02), New Resources Firm Power (NR-02), and Firm Power Products and Services (FPS-96), rate schedules.
Such power is not available for the PF Exchange Program rate, the PF Exchange Subscription rate, and the Residential Load rate.

Construction, Test and Start-Up, and Station Service power must be used in the manner specified below:

a. Power sold for construction is to be used in the construction of the project.

b. Power sold for test and start-up may be used prior to commercial operation, both to bring the project online and to ensure that the project is working properly.

c. Power sold for station service may be purchased at any time following commercial operation of the project. Once the project has been energized for commercial operation, the Purchaser may use station service power for start-up, shutdown, normal operations, and operations during a shutdown period.

d. Power sold for Construction, Test and Start-Up, and Station Service is not available for replacement of lost generation for forced or planned outages or resource underperformance.

6. Core Subscription Products

BPA's Core Subscription Products are described in the BPA Product Catalog. Core Subscription Products are available at the posted rates for customers who have a right to purchase them.

The core products are:

- Actual Partial Service Product – Simple/Complex
- Block Product
- Block Product with Factoring
- Block Product with Shaping Capacity
- Full Service Product

7. Customer System Peak (CSP)

CSP is the largest measured HLH Total Retail Load amount in kilowatts for the billing period.

8. Full Service Product

Full Service is a core Subscription product that is available to purchasers who have a right to purchase from BPA for their requirements. This product is available to customers who either have no resources or whose resources meet the criteria for small, non-dispatchable resources.

9. Industrial Firm Power (IP)

Industrial Firm Power (IP) is electric power that BPA will make continuously available to a DSI Purchaser subject to the terms of the Purchaser's power sales contract with BPA. Deliveries may be reduced or interrupted as permitted by the terms of the Purchaser's power sales contract with BPA. Adjustments as provided in the Purchaser's power sales contract shall be made for power restricted to provide reserves.

10. Load Variance

For core Subscription products, Load Variance is defined as the variability in monthly energy consumption within the BPA customer's system. Through the Load Variance charge under the Full and Actual Partial Service Products, the customer's billing factors will follow actual consumption. Load Variance is not applicable to Block Product purchases. For purposes of pricing and rate tests under Pre-Subscription contracts, the Load Variance charge is deemed to correspond to the PF-96 Load Shaping charge.

11. New Resource Firm Power (NR)

New Resource Firm Power (NR) is electric power (capacity and energy) that BPA will make continuously available:

a. for any NLSL; and

b. for Firm Power purchased by IOUs pursuant to power sales contracts with BPA.

NR is to be used to meet the Purchaser's firm power load within the PNW. Deliveries of NR may be reduced or interrupted as permitted by the terms of the Purchaser's power sales contract with BPA.

NR is guaranteed to be continuously available to the Purchaser during the period covered by its contractual commitment, except for reasons of certain uncontrollable forces and *force majeure* events. NR is power where BPA agrees to provide operating reserves in accordance with the standards established by the NERC, WSCC, and the NWPP.

12. Nonfirm Energy (NF)

Nonfirm Energy Power (NF) is energy that is supplied or made available by BPA to a Purchaser under an arrangement that does not have the guaranteed continuous availability feature of Firm Power. NF is sold primarily under the NF rate schedule, NF-02. NF also may be supplied under the NF-02 rate schedule to the

WSPP subject to terms and conditions agreed upon by the members participating in the WSPP and in accordance with BPA policy for such arrangements. NF that has been purchased under a guarantee provision in the NF rate schedule shall be provided to the Purchaser in accordance with the provisions of that schedule and the power sales contract if applicable. BPA may make NF available to purchasers both inside and outside the United States.

13. Priority Firm Power (PF)

Priority Firm Power (PF) is electric power (capacity and energy) that BPA will make continuously available for direct consumption or resale by public bodies, cooperatives, and Federal agencies. Utilities participating in the Residential Exchange under section 5(c) of the Northwest Power Act may purchase PF pursuant to their Residential Exchange contracts with BPA. PF is not available to serve NLSLs. Deliveries of PF may be reduced or interrupted as permitted by the terms of the Purchaser's power sales contract with BPA.

PF is guaranteed to be continuously available to the Purchaser during the period covered by its contractual commitment, except for reasons of certain uncontrollable forces and *force majeure* events. PF is power where BPA's TBL provides operating reserves in accordance with the standards established by the NERC, WSCC, and NWPP.

14. Regulation and Frequency Response

Regulation and frequency response is the generating capacity of a power system that is immediately responsive to Automatic Generation Control (AGC) signals without human intervention. Regulation and frequency response is required to provide AGC response to load and generation fluctuations in an effective manner and to maintain desired compliance with NERC AGC Control Performance.

15. Residential Exchange Program Power

Residential Exchange Program Power is power BPA sells to a Purchaser pursuant to the Residential Exchange Program. Under section 5(c) of the Northwest Power Act, BPA "purchases" power from PNW utilities at a utility's Average System Cost (ASC). BPA then offers, in exchange, to "sell" an equivalent amount of electric power to that customer at BPA's PF rate applicable to exchanging utilities. The amount of power purchased and sold is equal to the utility's eligible residential and small farm load. Benefits must be passed directly to the utility's residential and small farm customers.

16. Slice Product

The Slice product is a power sale based upon an eligible customer's annual net firm requirements load and is shaped to BPA's generation from the FCRPS over the year. The Slice product is not a sale or lease of any part of the ownership of, or operational rights to the FCRPS. Slice purchasers are entitled to a fixed percentage of the energy generated by the FCRPS. The Slice purchaser's percentage entitlements are set by contract. The Slice product includes both service to net requirements firm load as well as an advance sale of surplus power.

B. Definition of Rate Schedule Terms

1. 2002 Contract

A 2002 contract is a contract for service in the FY 2002 through 2006 rate period that is signed after January 1, 1999.

2. Annual Billing Cycle

The Annual Billing Cycle is the 12 months beginning with the customer's first monthly power bill for deliveries in the first billing month starting on or after October 1.

3. Billing Demand

The Purchaser's Billing Demand is the amount of capacity to which the demand charge specified in the rate schedule is applied. When the rate schedule includes charges for several products, there may be a Billing Demand quantity for each product. The calculation of Billing Demand is described in the customer's contract.

4. Billing Energy

The Purchaser's Billing Energy is the amount of energy to which the energy charge specified in the rate schedule is applied. When the rate schedule includes charges for several products, there may be a Billing Energy quantity for each product. Billing Energy is divided into HLH and LLH for this rate period.

5. California Independent System Operator (California ISO)

The FERC regulated control area operator of the ISO transmission grid. Its responsibilities include providing non-discriminatory access to the transmission grid, managing congestion, maintaining the reliability and security of the grid, and providing billing and settlement services. The ISO has no affiliation with any market participant.

6. California ISO Spinning Reserve Capacity

The portion of unloaded synchronized generating capacity, controlled by the California ISO, which is capable of being loaded in 10 minutes, and which is capable of running for at least two hours.

7. California ISO Supplemental Energy

Energy from generating units and other resources which have uncommitted capacity following finalization of the hour-ahead schedules and for which scheduling coordinators have submitted bids to the California ISO at least 30 minutes before the commencement of the settlement period.

8. California Power Exchange (CalPX)

An independent agency responsible for conducting an auction for the generators seeking to sell energy and for loads which are not otherwise being served by bilateral contracts. The CalPX is responsible for scheduling generation in its scheduling (*e.g.,* day-ahead) markets, for determining hourly market clearing prices for its market, and for settlement and billing for suppliers and Utility Distribution Companies (UDC) using its market.

9. Contract Demand

The Contract Demand is the maximum number of kilowatts that the Purchaser agrees to purchase and BPA agrees to make available, subject to any limitations included in the applicable contract between BPA and the Purchaser.

10. Contract Energy

Contract Energy is the maximum number of kilowatthours that the Purchaser agrees to purchase and BPA agrees to make available, subject to any limitations included in the applicable contract between BPA and the Purchaser.

11. Control Area

A Control Area is the electrical (not necessarily geographical) area within which a controlling utility operating under all NERC standards has the responsibility to adjust its generation on an instantaneous basis to match internal load and powerflow across interchange boundaries to other Control Areas.

12. Decremental Cost

Unless otherwise specified in a contractual arrangement, Decremental Cost as applied to Nonfirm Energy transactions is defined as:

a. All identifiable costs (expressed in mills/kWh) associated with the use of a displaceable thermal resource or end-use load with alternate fuel source to serve a purchaser's load that the purchaser is able to avoid by purchasing power from BPA, rather than generating the power itself or using an alternate fuel source; or

b. All identifiable costs (expressed in mills/kWh) to serve the load of a displaceable purchase of energy that the purchaser is able to avoid by choosing not to make the alternate energy purchase.

All identifiable costs as used in the above definitions may be reduced to reflect costs of purchasing BPA energy such as transmission costs, losses, or loopflow constraints that are agreed to by BPA and the Purchaser.

13. Delivering Party

The entity supplying the capacity and/or energy to be transmitted at Point(s) of Interconnection.

14. Demand Entitlement

For purchases made under contracts for core Subscription products, Demand Entitlement is the largest HLH amount of power in kilowatts that the purchaser is entitled to receive from BPA during the billing period as specified in the contract.

15. Discount Period

The end of the rate period or the customer's contract term, whichever comes first.

16. Dow Jones Mid-C Indexes (DJ Mid-C Indexes)

Average HLH (or peak) and average LLH (or offpeak) price indices for sales of electricity at delivery points along the Mid-Columbia River, as published by Dow Jones & Company, Inc.

17. Electric Power

Electric Power is electric peaking capacity (kilowatts) and/or electric energy (kilowatthours).

18. Energy Entitlement

For purchases made under contracts for core Subscription products, HLH and LLH Energy Entitlement is the sum in kilowatthours of amounts for HLH and LLH energy respectively, that the purchaser is entitled to receive from BPA as specified in the contract.

19. Federal System

The Federal System is the generating facilities of the FCRPS, including the Federal generating facilities for which BPA is designated as marketing agent; the Federal facilities under the jurisdiction of BPA; and any other facilities:

a. from which BPA receives all or a portion of the generating capability (other than station service) for use in meeting BPA's loads to the extent BPA has the right to receive such capability. "BPA's loads" do not include any of the loads of any BPA customer that are served by a non-Federal generating resource purchased or owned directly by such customer which may be scheduled by BPA;

b. which BPA may use under contract or license; or

c. to the extent of the rights acquired by BPA pursuant to the 1961 U.S.-Canada Treaty relating to the cooperative development of water resources of the Columbia River Basin.

20. Firm Power (PF-02, IP-02, NR-02, RL-02)

Firm Power is electric power (capacity and energy) that BPA will make continuously available under contracts executed pursuant to section 5 of the Northwest Power Act.

21. Full Service Customer

A Full Service customer is one who is purchasing power from BPA through the Full Service Product.

22. Generation System Peak (GSP)

The GSP is the hour of the largest HLH output of the Federal System that occurs during the customer's billing period.

23. Heavy Load Hours (HLH)

Heavy Load Hours (HLH) are all those hours in the peak period hour ending 7 a.m. to the hour ending 10 p.m., Monday through Saturday, Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time, as applicable). There are no exceptions to this definition; that is, it does not matter whether the day is a normal working day or a holiday.

24. Inventory Augmentation (or Inventory Solution)

BPA's action to supplement the capability of the Federal System Resources, as a result of BPA's Subscription process.

25. Light Load Hours (LLH)

Light Load Hours (LLH) are all those hours in the offpeak period hour ending 11 p.m. to the hour ending 6 a.m., Monday through Saturday and all hours Sunday, Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time, as applicable).

26. Measured Demand

The Purchaser's Measured Demand is that portion of its Metered or Scheduled Demand provided by BPA to the Purchaser. If more than one class of power is delivered to any point of delivery, the portion of the measured quantities assigned to any class of power shall be as specified by contract. Any delivery of Federal power not assigned to classes of power delivered under other agreements shall be included in the Measured Demand for PF, NR, or IP power as applicable.
The portion of the total Measured Demand so assigned shall constitute the Measured Demand for each such class of power. Any residual quantity, after determination of the Purchaser's contractual entitlement at a particular rate, is considered "unauthorized." Unauthorized increases are billed in accordance with the provisions of these GRSPs.

In determining Measured Demand for any Purchaser who experiences an outage as defined pursuant to the Purchaser's agreement with BPA, BPA shall adjust any abnormal Integrated Demand due to, or resulting from:

a. emergencies or breakdowns on, or maintenance of, the Federal System Facilities; and

b. emergencies on the Purchaser's facilities to the extent BPA determines that such facilities have been adequately maintained and prudently operated.

BPA will follow its billing process in establishing the Billing Demand should an outage cause an unusual Billing Demand quantity.

BPA will not give outage credits for demand.

27. Measured Energy

The Purchaser's Measured Energy is that portion of its Metered or Scheduled Energy that is provided by BPA to the Purchaser during a particular diurnal period (HLH or LLH) in a billing period. If more than one class of power is delivered to any point of delivery, the portion of the measured quantities assigned to any class of power shall be as specified by contract. Any delivery of Federal power not assigned to classes of power delivered under other agreements shall be included in the Measured Energy for PF, NR, or IP power as applicable. The portion of the total Measured Energy so assigned shall constitute the Measured Energy for each such class of power. Any residual quantity, after determination of the Purchaser's contractual entitlement at a particular rate, is considered "unauthorized." Unauthorized increases are billed in accordance with the provisions of these GRSPs.

28. Metered Demand

The Metered Demand in kilowatts shall be the largest of the 60-minute clock-hour Integrated Demands at which electric energy is delivered to a purchaser:

a. at each point of delivery for which the Metered Demand is the basis for determination of the Measured Demand;

b. during each time period specified in the applicable rate schedule; and

c. during any billing period.

Such largest Integrated Demand shall be determined from measurements made in accordance with the provisions of the applicable contract and these GRSPs. This amount shall be adjusted as provided herein and in the applicable agreement between BPA and the Purchaser.

29. Metered Energy

The Metered Energy for a purchaser shall be the number of kilowatthours that are recorded on the appropriate metering equipment, adjusted as specified in the applicable agreement and delivered to a Purchaser:

a. at all points of delivery for which metered energy is the basis for determination of the Measured Energy; and

b. during any billing period.

30. Monthly Federal System Peak Load

Monthly Federal System Peak Load is the peak load on the Federal System during a customer's billing month, determined by the largest hourly integrated demand produced from system generating plants in BPA's control area and scheduled imports for BPA's account from other control areas.

31. NP15

The portion of the California ISO's control area north of transmission path 15.

32. NW1 (COB)

California PX and California ISO designation for delivery at COB (Captain Jack/Malin).

33. NW3 (NOB)

CalPX and California ISO designation for delivery at NOB.

34. Partial Service Customer

A Partial Service customer is any customer that is not a Full Service customer.

35. Point of Delivery (POD)

A POD is the contractual interconnection point where power is delivered to the customer. Typically, a point of delivery is located at a substation site, but it could be located at the change of ownership point on a transmission line.

36. Point of Integration (POI)

A Point of Integration is the contractual interconnection point where power is received from the customer. Typically a point of integration is located at a resource site, but it could be located at some other interconnection point to receive system power from the customer.

37. Point of Interconnection (POI)

A Point of Interconnection is a point where the facilities of two entities are interconnected.

38. Points of Metering (POM)

The POM shall be those points specified in the contract at which Total Retail Load and Metered Amounts are measured.

39. Pre-Subscription Contract

A contract for service in the FY 2002 through 2006 rate period that was signed prior to January 1, 1999, is a Pre-Subscription Contract.

40. Purchaser

Pursuant to the terms of an agreement and applicable rate schedule(s), a Purchaser contracts to pay BPA for providing a product or service.

41. Receiving Party

The entity receiving the capacity and/or energy transmitted by BPA to a Point(s) of Delivery.

42. Retail Access

Retail Access is non-discriminatory retail distribution access mandated either by Federal or state law which grants retail electric power consumers the right to choose their electricity supplier.

43. Scheduled Demand

For purposes of applying the rates herein to applicable purchases by the Purchaser, the Scheduled Demand in kilowatts is the largest of the hourly demands at which electric energy is scheduled by BPA for delivery to a purchaser:

a. to each system for which Scheduled Demand is the basis for determination of the Measured Demand;

b. during each time period specified in the applicable rate schedule; and

c. during any billing period.

Scheduled Demand is deemed delivered for the purpose of determining Billing Demand.

44. Scheduled Energy

For purposes of applying the rates herein to applicable purchases by the Purchaser, Scheduled Energy in kilowatthours shall be the sum of the hourly demands at which electric energy is scheduled by BPA for delivery to a purchaser:

a. for each system for which Scheduled Energy is the basis for determination of the Measured Energy; and

b. during any billing period.

Scheduled Energy is deemed delivered for the purpose of determining Billing Energy.

45. Slice Revenue Requirement

The Slice Revenue Requirement is comprised of the items in BPA's PBL revenue requirement used to calculate the Slice product charge, as identified in the PBL's 2002 and 2007 Power rate cases. *See* Table D.

46. Subscription

Subscription refers to the Power Subscription Strategy issued by BPA on December 21, 1998, which is BPA's policy for power sales beginning FY 2002.

47. Subscription Contract

See 2002 Contract.

48. Total Plant Load (TPL)

Total Plant Load means a DSI customer's total electrical energy load at facilities eligible for BPA service during any given time period whether the customer has chosen to serve its load with BPA power or non-Federal power.

49. Total Retail Load (TRL)

Total Retail Load (TRL) is all electric power consumption including distribution system losses, within a utility's distribution system as measured at metering points, adjusted for unmetered loads or generation. No distinction is made between load that is served with BPA power and load that is served with power from other sources. For DSIs, TRL is called Total Plant Load.

The TRL billing determinant for the Load Variance Charge will be adjusted for any load that is designated as exempt from the charge in accordance with the customer's Power Sales Agreement.

50. Utility Distribution Company (UDC)

A company that owns and maintains the distribution facilities used to serve end-use customers.

APPENDIX A

2002 SLICE RATE METHODOLOGY

METHODOLOGY TO CALCULATE SLICE RATE AND SLICE TRUE-UP ADJUSTMENT CHARGE

This Appendix A was an Attachment to Chapter 8 of the 2002 Supplemental Power Rate Proposal Administrator's Final Record of Decision (2002 Supplemental ROD, WP-02-A-09). The version contained in the 2002 Supplemental ROD was a "red-lined" version that showed changes from the version contained in the May 2000 ROD. The version contained in this Appendix A is the same version as the one contained in the 2002 Supplemental ROD, but with "red-lined" changes accepted.

Table 1: Slice Product Costing and True-Up Table begins on page 185.

ATTACHMENT TO CHAPTER 8

METHODOLOGY TO CALCULATE SLICE RATE AND SLICE TRUE-UP ADJUSTMENT CHARGE

Section 1. PURPOSE

The Slice Methodology is designed as a means for providing a consistent method of calculating the rate for Slice and conducting the annual true-up for 10 years of the contract. Because there is some uncertainty regarding the calculation of the Slice rate in a rate period subsequent to the FY 2002-2006 rate period, the Slice Methodology is intended to bring some stability to the calculation of the rate. The Slice Methodology is not intended to predetermine the actual rate a Slice purchaser will pay in any rate period; rather, the Slice Methodology proposes a set of cost categories that will make up the Slice Revenue Requirement and the manner in which such costs may be trued up annually.

Section 2. TERM OF THE METHODOLOGY

After FERC approval, this methodology shall take effect on October 1, 2001, and shall terminate on the earlier of midnight September 30, 2011, or a date established by FERC.

Section 3. DEFINITIONS

Actual Slice Revenue Requirement means the use of audited actual financial data in the cost categories comprising the Slice Revenue Requirement.

Capital Expenses means depreciation expense (recovery of the investment) and net interest expense (recovery of financing costs). Depreciation standards (*e.g.*, duration of useful life) used for the recovery of capital investments under the Slice contract will be the same as those used by BPA to set power rates generally, and will not change from those used in the development of Table 1, Slice Product Costing and True-Up Table, unless BPA adopts a new depreciation study.

Contracted Loads for each five-year rate period shall be the average of five Fiscal Year (FY) loads contracted for in annual aMW for the Public Agency customers, DSI customers to be served with FBS resources, IOU customers to be served with FBS resources, and the Preexisting Multiyear Contracts that are known to BPA.

Forecasted Loads for each five-year rate period shall be the average of five forecasted FY loads in annual aMW that was included in the applicable Final Power Rate Proposal for the Public Agency loads, DSI loads to be served with FBS resources, IOU loads served with FBS resources, and Preexisting Multiyear Contracts.

Initial Implementation Expenses means the expenses of implementing the Slice product for which BPA was reimbursed, prior to October 1, 2001, pursuant to the Master Agreement to Enable the Technical Development of a Slice of System Power Sale (Master Agreement).

Minimum Required Net Revenues means the amount by which BPA's payments to the U.S. Treasury for generation amortization and irrigation assistance exceed the total non-cash expenses in the Actual Slice Revenue Requirement.

Preexisting Multiyear Contracts means BPA's contracts for power sales, which have been executed as of June 21, 1999, with a term length that extends beyond the first year of the FY 2002-2006 rate period.

Slice Revenue Requirement means the operating and Capital Expenses and credits included in the Slice Rate which are established in the generation Revenue Requirement Study for the applicable rate periods and are subject to the criteria for inclusion of new costs or credits. The costs and credit categories included in the Slice Revenue Requirement are listed in Table 1, Slice Product Costing and True-Up Table.

Slice System Resources means the FBS resources identified in the Slice contract.

System Obligations means those operational or contractual obligations of the FBS that are identified in the Slice contract.

Section 4. METHODOLOGY

A. Slice Rate Calculation

The monthly rate for the Slice product will be calculated in the following manner:

Monthly rate for the Slice product per 1 percent of the Slice System = (Annual Average Slice Revenue Requirement / 12) /100 where the Slice Revenue Requirement is calculated as described in section B below. The monthly rate for the Slice product will be adjusted by the application of the Load-Based Cost Recovery Adjustment Clause (LB CRAC). The LB CRAC is applicable for the FY 2002-2006 rate period as defined in the 2002 Final Supplemental Proposal for Wholesale Power Rates.

For the FY 2002-2006 rate period, the Slice Revenue Requirement will contain the costs and credits displayed in Table 1, Slice Product Costing and True-Up Table.

For the FY 2007-2011 rate period, the Slice Revenue Requirement will contain the costs and credits estimated in the FY 2007 rate case for the cost and credit categories identified in Table 1, Slice Product Costing and True-Up Table, and any other currently unidentified cost or credit, as described in section B. 3. below.

B. Slice Revenue Requirement

1. Uniform Application Throughout the Rate Period

The Slice Revenue Requirement is a five-year annual average amount for the applicable rate period. The Slice Rate will remain constant during the applicable rate period.

2. Cost and Credit Categories Used to Set the Slice Revenue Requirement

The cost and credit categories used to set the Slice Revenue Requirement and the Actual Slice Revenue Requirement shall be those defined in the generation Revenue Requirement Study for the 2002 Final Power Rate Proposal and listed in Table 1, Slice Product Costing and True-Up Table.

For FY 2002 only, the total of all Initial Implementation Expenses that BPA received under the Master Agreements shall be included in the Actual Slice Revenue Requirement.

3. Inclusion of New Costs or Credits

PBL costs or credits not otherwise specifically dealt with in the Slice Revenue Requirement, or excluded there from as specified in section B. 4. below, may be included in both the Slice Revenue Requirement and the Actual Slice Revenue Requirement, if and to the extent that:

Such PBL costs or credits could be properly includable in PBL's wholesale power rates; and either

a) Such PBL costs or credits are: (1) incurred by PBL to provide service to customers other than Slice purchasers; and (2) incurred to provide service to or otherwise benefit Slice purchasers;

OR

b) Such PBL costs or credits are not incurred to provide service to customers other than Slice purchasers, nor to provide service to or otherwise benefit Slice purchasers.

4. Costs Excluded from the Slice Revenue Requirement

Excluded costs include, but are not limited to the following:

- All transmission costs (other than those associated with the transmission of System Obligations and GTAs);

- All power purchase costs (with the exception of net Inventory Solution costs);

- All PNRR and hedging costs, with the exception of those hedging costs incurred to implement the forecasted Inventory Solution; and

- All costs not permitted to be included in the Slice Revenue Requirement as specified by section B. 3. above.

5. Credits

a. Systemwide Credits

Systemwide credits are any monetary credits that PBL forecasts to receive that are associated with the costs identified in the Slice Revenue Requirement. Systemwide credits shall be included in both the Slice Revenue Requirement and the Actual Slice Revenue Requirement as a credit. The credits include, but are not limited to:

- Credits from the U.S. Treasury for PBL's settlement payment to the Colville Tribe;

- Credits from the U.S. Treasury for section 4(h)(10)(c) of the Northwest Power Act;

- Credits from the U.S. Treasury for the FCCF; and

- Revenues BPA receives for meeting System Obligations (including revenues received for Congestion Management or PNCA transactions).

b. Transmission Surcharge

As provided for under separate rate and contract, BPA's TBL may impose a transmission surcharge on the Slice purchaser's use of the BPA transmission system. Any revenues received by the TBL pursuant to such surcharge will be credited to PBL's total Actual Slice Revenue Requirement, and will be reflected in the Slice purchaser's True-Up Adjustment. Repayment of such funds by the PBL to TBL, if any, shall be included in the Actual Slice Revenue Requirement.

c. Purchaser-Specific Credits and Other Contract Related Charges

All Slice purchaser-specific credits and other Slice purchaser-specific charges resulting from the implementation of the Slice contract shall be applied as an adjustment to the Slice True-Up Adjustment Charge for each specific Slice purchaser. The adjustment for credits and charges associated with the implementation of the Slice contract will be defined in the Slice contract.

6. **Inapplicability of Financial-Based Cost Recovery Adjustment Clause (FB CRAC), the Safety-Net Cost Recovery Adjustment Clause (SN CRAC), the Targeted Adjustment Clause (TAC), and the Dividend Distribution Clause (DDC)**

   Neither the Slice Rate nor the Slice True-up Adjustment Charge paid by Slice purchasers will be subject to the FB CRAC, the SN CRAC, the TAC, or the DDC identified in the GRSPs or any successor thereto.

7. **Applicability of the Load-Based CRAC**

   For the FY 2002- 2006 period, the LB CRAC will apply to the Slice Rate.

8. **Net Cost of the Inventory Solution**

   BPA has forecasted firm energy purchases that supplement the capability of FBS Resources (Inventory Solution) to meet the forecasted loads. The cost of the Inventory Solution shall be included in both the Slice Revenue Requirement and the Actual Slice Revenue Requirement on a net cost basis. The forecasted net cost of the Inventory Solution (NCIS) shall be calculated as: (1) the total expenses for the Inventory Solution; less (2) the total revenues for the sale of such power; both as projected by BPA. Since Slice purchasers bear the responsibility for their proportionate share of any loss of FBS resources or capability thereof, the Inventory Solution will not include such replacements. The forecasted net cost of the Inventory Solution to be included in the Slice Revenue Requirement for the FY 2002-2006 rate period is identified in Table 1. An additional adjustment is included in the Actual Slice Revenue Requirement that is based on the change in the magnitude of the Inventory Solution expressed in MW, the calculation of which is described in section C. 2. below.

C. Slice True-Up Adjustment Charge

The Slice True-Up Adjustment Charge is a monthly charge applied to the Slice product that is expressed in terms of dollars per percent Slice selected. The Slice True-Up Adjustment Charge consists of the Annual Slice True-Up Adjustment that is calculated once each fiscal year and is applied to specific months of the fiscal year. The Slice True-Up Adjustment Charge for each month shall be calculated in the following manner:

$STUAC_M = ASTU_M$

Where:

$STUAC_M$ is the Slice True-Up Adjustment Charge for month M of the rate period.

$ASTU_M$ is the portion of the Annual Slice True-Up Adjustment applicable for month M.

1. Annual Slice True-Up Adjustment

The Annual Slice True-Up Adjustment shall be calculated for each fiscal year as soon as independently audited actual financial data are available. As necessary, the Actual Slice Revenue Requirement shall include a Minimum Required Net Revenues component to ensure coverage of annual cash requirements. The Annual Slice True-Up Adjustment shall be calculated to be the annual Slice Revenue Requirement for the FY subtracted from the Actual Slice Revenue Requirement for such FY as shown in Attachment 1. The Annual Slice True-Up Adjustment shall be applied either as a one month credit (if the adjustment is negative) or as a three-month charge (if the adjustment is positive, and spread equally across the three months) following the month the Annual Slice True-Up Adjustment is calculated.

D. IOU Settlement Charge

Each monthly Slice bill will include a line item to account for the proposed increment in the IOU cash settlement above the cash settlement amount included in the Slice Revenue Requirement in the May Proposal. The revenues from this incremental amount will not be included in any calculation of the LB CRAC.

The monthly adjustment per one-percent Slice will be:
[Incremental amount of IOU Settlement costs in the Supplemental Rate Case ROD/12/100] = $ per month per one-percent Slice.

TABLE 1
Slice Product Costing and True-Up Table

Table 1

		SLICE PRODUCT COSTING AND TRUE-UP TABLE							
			A	B	C	D	E		F
1	**PBL Costs ($000)**	2002-2006	2002	2003	2004	2005	2006		TOTAL
2	**GENERATION COSTS**	Audited	Projected →						
3	Federal Base System	Actuals							
4	Hydro								
5	Upstream benefits		$ 1,990	$ 2,050	$ 2,111	$ 2,174	$ 2,240		$ 10,565
6	Corps of Engineers O&M		$ 108,000	$ 112,000	$ 112,000	$ 112,000	$ 112,000		$ 556,000
7	Corps Depreciation		$ 73,329	$ 75,497	$ 78,292	$ 81,258	$ 83,620		$ 391,996
8	U.S. Fish & Wildlife O&M		$ 15,400	$ 16,197	$ 16,995	$ 17,892	$ 18,789		$ 85,273
9	Bureau of Reclamation O&M		$ 47,000	$ 48,300	$ 48,300	$ 48,300	$ 48,300		$ 240,200
10	Bureau Depreciation		$ 19,470	$ 20,043	$ 20,535	$ 21,009	$ 21,516		$ 102,573
11	Colville Settlement		$ 16,000	$ 16,000	$ 16,000	$ 16,000	$ 16,000		$ 80,000
12	Packwood Dam		$ 2,343	$ 2,577	$ 2,835	$ 3,118	$ 3,430		$ 14,301
13	Net Interest Expense		$ 157,914	$ 158,579	$ 166,657	$ 176,226	$ 177,170		$ 836,546
14	**Subtotal**		**$ 441,446**	**$ 451,243**	**$ 463,724**	**$ 477,977**	**$ 483,065**		**$ 2,317,455**
15	Fish and Wildlife								
16	Expense		$ 131,700	$ 138,000	$ 140,100	$ 142,900	$ 144,400		$ 697,100
17	Amortization		$ 19,772	$ 21,842	$ 23,737	$ 25,394	$ 26,407		$ 117,152
18	Net Interest Expense		$ 6,540	$ 6,759	$ 7,181	$ 7,259	$ 7,166		$ 34,905
19	**Subtotal**		**$ 158,012**	**$ 166,601**	**$ 171,018**	**$ 175,553**	**$ 177,973**		**$ 849,157**
20	Trojan								
21	Decommissioning		$ 9,600	$ 4,200	$ 2,600	$ 2,600	$ 2,600		$ 21,600
22	Debt Service		$ 9,947	$ 9,954	$ 9,964	$ 9,989	$ 10,009		$ 49,863
23	**Subtotal**		**$ 19,547**	**$ 14,154**	**$ 12,564**	**$ 12,589**	**$ 12,609**		**$ 71,463**
24	WNP #1								
25	O&M		$ 400	$ 384	$ 384	$ 384	$ 384		$ 1,936
26	Debt Service		$ 177,704	$ 167,856	$ 174,623	$ 167,910	$ 179,992		$ 868,085
27	**Subtotal**		**$ 178,104**	**$ 168,240**	**$ 175,007**	**$ 168,294**	**$ 180,376**		**$ 870,021**
28	WNP #2								
29	O&M/Capital Requirements		$ 154,094	$ 163,824	$ 170,724	$ 173,824	$ 179,824		$ 842,290
30	Debt Service		$ 197,442	$ 244,980	$ 233,624	$ 187,825	$ 211,976		$ 1,075,847
31	**Subtotal**		**$ 351,536**	**$ 408,804**	**$ 404,348**	**$ 361,649**	**$ 391,800**		**$ 1,918,137**
32	WNP #3								
33	Debt Service		$ 153,720	$ 152,993	$ 149,232	$ 149,480	$ 147,836		$ 753,261
34	**Total**		**$ 1,302,364**	**$ 1,362,035**	**$ 1,375,894**	**$ 1,345,542**	**$ 1,393,659**		**$ 6,779,494**
35									
36	New Resources								
37	Idaho Falls		$ 3,740	$ 3,737	$ 3,744	$ 3,754	$ 3,754		$ 18,729
38	Cowlitz		$ 14,914	$ 14,987	$ 15,051	$ 15,123	$ 15,196		$ 75,271
39	Firm Purchased Power		$ 17,723	$ 17,953	$ 18,187	$ 18,435	$ 18,681		$ 90,978
40	Competitive Acquisitions		$ 12,158	$ 12,340	$ 12,526	$ 12,713	$ 12,904		$ 62,642
41	Columbia Hills (CARES)		$ 4,323	$ 4,359	$ 4,397	$ 4,446	$ 4,490		$ 22,015
42	Wheeling Power Purchase		$ 1,242	$ 1,253	$ 1,264	$ 1,275	$ 1,287		$ 6,321
43	Other Acquisitions		$ -	$ -	$ -	$ -	$ -		$ -
44	**Total**		**$ 36,377**	**$ 36,677**	**$ 36,982**	**$ 37,312**	**$ 37,631**		**$ 184,978**
45									
46	Legacy Conservation								
47	Conservation expense		$ 18,201	$ 16,613	$ 16,913	$ 17,313	$ 17,613		$ 86,651
48	Generation Billing Credits		$ 7,934	$ 7,898	$ 7,866	$ 7,834	$ 7,785		$ 39,317
49	Conservation Financing		$ 5,578	$ 5,577	$ 5,577	$ 5,577	$ 5,577		$ 27,886
50	Conservation Amortization		$ 59,337	$ 55,586	$ 47,125	$ 43,179	$ 37,650		$ 242,877
51	Conservation Interest		$ 38,822	$ 39,345	$ 35,237	$ 34,779	$ 32,001		$ 180,184
52	**Subtotal**		**$ 129,872**	**$ 125,019**	**$ 112,718**	**$ 108,681**	**$ 100,626**		**$ 576,915**
53	Energy Services Business		$ 11,663	$ 11,690	$ 11,601	$ 11,475	$ 11,444		$ 57,873
54	Other Generation Costs								
55	BPA Programs								
56	CSRS Pension Expense		$ 27,600	$ 17,550	$ 15,450	$ 13,250	$ 11,600		$ 85,450
57	Power Marketing		$ 16,000	$ 15,700	$ 8,800	$ 6,800	$ 5,000		$ 52,300
58	Power Scheduling		$ 20,900	$ 12,800	$ 12,100	$ 12,800	$ 12,700		$ 71,300
59	Inventory Solution Hedging Activities		$ -	$ -	$ -	$ -	$ -		$ -
60	Generation Oversight		$ 2,964	$ 2,950	$ 3,050	$ 3,050	$ 3,150		$ 15,163
61	Administrative & Support Services		$ 17,350	$ 16,650	$ 16,650	$ 16,650	$ 16,650		$ 83,950
62	Power Planning Council		$ 5,100	$ 5,100	$ 5,100	$ 5,100	$ 5,100		$ 25,500
63	Miscellaneous Depreciation		$ 4,296	$ 4,693	$ 4,383	$ 3,411	$ 2,973		$ 19,756
64	Geothermal Demonstration		$ 15,768	$ 15,768	$ 15,768	$ 15,768	$ 15,768		$ 78,840
65	Renewables		$ 3,091	$ 2,870	$ 2,683	$ 2,551	$ 2,459		$ 13,654
66	Contingency Resources		$ 391	$ 369	$ 317	$ 395	$ 342		$ 1,814
67	Net Interest Expense		$ 406	$ 359	$ 325	$ 312	$ 308		$ 1,710
68	Between Business Line Expense		$ 4,000	$ 4,000	$ 4,000	$ 4,000	$ 4,000		$ 20,000
69	Other								
70	WNP #3 Plant		$ 3,086	$ 3,169	$ 3,169	$ 3,169	$ 3,169		$ 15,762
71	**Total Other Generation Costs**		**$ 120,952**	**$ 101,978**	**$ 91,795**	**$ 87,256**	**$ 83,218**		**$ 485,199**
72	**Minimum Required Net Revenues**		$ -	$ -	$ -	$ -	$ -		$ -
73	**COSA Table Subtotal**		**$ 1,601,227**	**$ 1,637,398**	**$ 1,628,989**	**$ 1,590,266**	**$ 1,626,578**		**$ 8,084,458**

Table 1 (continued)

			A	B	C	D	E		F
	PBL Costs ($000)	2002-2006	2002	2003	2004	2005	2006		TOTAL
		Audited	Projected						
74		Actuals							
75	Net Residential Exchange Costs		$ -	$ -	$ -	$ -	$ -		$ -
76	Subscription Settlement Costs (900 aMW's in $)		$ 69,725	$ 69,725	$ 69,725	$ 69,725	$ 69,725		$ 348,626
77									
78	Slice Initial Implementation Expenses		$ -	Not applicable	Not applicable	Not applicable	Not applicable		$ -
79	Slice Implementation Expenses		$ -	$ -	$ -	$ -	$ -		$ -
80									
81	CEA Transmission Costs		$ 13,514	$ 17,105	$ 26,685	$ 26,685	$ 26,685		$ 110,675
82	Ancillary and Reserve Service Costs		$ 10,000	$ 10,000	$ 8,000	$ 8,000	$ 8,000		$ 44,000
83	PBL PF Trans. Pass-Through Costs		$ -	$ -	$ -	$ -	$ -		$ -
84	PNCA & NTS Transmission Costs		$ 1,815	$ 1,815	$ 1,815	$ 1,815	$ 1,815		$ 9,075
85	General Transfer Agreement Costs		$ 47,200	$ 47,200	$ 47,200	$ 47,200	$ 47,200		$ 236,000
86									
87	**REVENUE REQUIREMENT CHECK**		**$ 1,743,482**	**$ 1,783,243**	**$ 1,782,414**	**$ 1,743,692**	**$ 1,780,003**	**0**	**$ 8,832,833**
88									
89	PF Conservation and Renewables Credit Costs								$ 95,104
90	IP Conservation and Renewables Credit Costs								$ 31,536
91	RL Conservation and Renewables Credit Costs								$ 21,900
92	LDD		$ 14,000	$ 14,000	$ 14,000	$ 14,000	$ 14,000		$ 70,000
93	S & I Rate Mitigation Costs		$ 4,000	$ 4,000	$ 4,000	$ 4,000	$ 4,000		$ 20,000
94	**Non-COSA Table Subtotal**								$ 238,540
95									
96	**Total PBL Revenue Requirement**								**$ 9,071,373**
97									
98	**Revenue Credits ($000)**								
99	Ancillary and Reserve Service Revs.		$ 80,380	$ 80,293	$ 81,127	$ 81,098	$ 81,025		$ 403,924
100	PBL PF Trans. Pass-Through Revs.		$ -	$ -	$ -	$ -	$ -		$ -
101	Canadian Entitlement Credit		$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000		$ 5,000
102									
103	COE & USBR Project Revenues		$ 8,100	$ 8,100	$ 8,100	$ 8,100	$ 8,100		$ 40,500
104	4(h)(10)(c)		$ 88,147	$ 91,007	$ 90,731	$ 92,873	$ 95,177		$ 457,935
105	Colville Credit		$ 4,600	$ 4,600	$ 4,600	$ 4,600	$ 4,600		$ 23,000
106	FCCF		$ 51,406	$ 33,261	$ 22,681	$ 16,079	$ 6,899		$ 130,326
107	Sup/Ent Cap; Irr. Pump		$ 938	$ 707	$ 471	$ 471	$ 471		$ 3,059
108	Energy Efficiency Revenues		$ 13,046	$ 13,345	$ 13,345	$ 13,345	$ 13,345		$ 66,426
109	Property Trnfrs & Misc.		$ 3,416	$ 3,416	$ 3,416	$ 3,416	$ 3,416		$ 17,080
110									
111	**Total Revenue Credits**								**$ 1,147,249**
112									
113	**Power Revenues Needed**								**$ 7,924,124**
114									
115	Firm System Augmentation (1282 aMWs on average)		$ 322,218	$ 336,766	$ 289,159	$ 323,744	$ 306,070		$ 1,577,958
116	DSI Augmentation (450 aMWs)		$ 113,888	$ 113,888	$ 113,888	$ 113,888	$ 113,888		$ 569,442
117	Conservation Augmentation (20,40,60,80,100 aMW)		$ 5,415	$ 10,831	$ 16,246	$ 21,662	$ 27,077		$ 81,231
118	**Total Cost of Inventory Solution**		**$ 441,522**	**$ 461,485**	**$ 419,294**	**$ 459,294**	**$ 447,036**		**$ 2,228,632**
120									
121	Revenue 1282 aMWs flat, 450 aMWs to DSIs		$ (327,235)	$ (327,235)	$ (327,235)	$ (327,235)	$ (327,235)		$ (1,636,175)
122	**Net Cost of Inventory Solution**		**$ 114,287**	**$ 134,250**	**$ 92,059**	**$ 132,060**	**$ 119,801**		**$ 592,457**
123									
124		($000)							
125	**Annual Slice Revenue Requirement**	**$ 1,703,316**							
126	**Monthly Slice Revenue Requirement**	**$ 141,943**				**Five Year Total**			**$ 8,516,581**
127	**One Percent of Monthly Requirement**	**$ 1,419.43**							
128									

FIRM POWER PRODUCTS AND SERVICES RATE (FPS-96R)

Updated to refer to the 2002 General Rate Schedule Provisions

INDEX
FIRM POWER PRODUCTS AND SERVICES RATE ADJUSTMENT
(FPS-96R)

FPS-96R Firm Power Products and Services 193

(FPS-96R, General Rate Schedule Provisions (GRSPs) for 2002 Unauthorized Increase Charge, is to be found in Section II.W of the 2002 GRSPs. Cost Contributions can be found in Section II.E of the 2002 GRSPs.)

SCHEDULE FPS-96R
FIRM POWER PRODUCTS AND SERVICES

SECTION I. AVAILABILITY

This rate schedule is available for the purchase of Firm Power, Capacity Without Energy, Supplemental Control Area Services, Shaping Services, and Reservation and Rights to Change Services for use inside and outside the Pacific Northwest during the period beginning October 1, 1996, and ending September 30, 2006.

Products and services available under this rate schedule are described in the 2002 GRSPs in Sections II.E and II.W of BPA's 2002 General Rate Schedule Provisions (GRSPs). BPA is not obligated to enter into agreements to sell products and services under this rate schedule or make power or energy available under this rate schedule if such power or energy would displace sales under the PF-96, NR-96, IP-96, or VI-96 rates schedules or their successors. Sales under the FPS-96 rate schedule are subject to BPA's GRSPs. Transmission service over Federal Columbia River Transmission System facilities shall be charged under the applicable transmission rate schedule. Ancillary services shall be available under, or at charges consistent with, the Ancillary Products and Services (APS) rate schedule for transmission.

This rate schedule supersedes the Surplus Firm Power (SP-93) and Emergency Capacity (CE-95) rate schedules. Rates under contracts that contain charges that escalate based on rates listed in this rate schedule shall include applicable transmission charges. For sales under this rate schedule, bills shall be rendered and payments due pursuant to BPA's Billing Procedures and/or as agreed to in purchase agreements.*

SECTION II. RATES, BILLING FACTORS, AND ADJUSTMENTS

For each product, the rate(s) for each product along with the associated billing factor(s) are identified below. Applicable adjustments, charges, and special rate provisions are listed for each product. This rate schedule contains four subsections, corresponding to the products offered under this rate schedule:

Section II.A. Firm Power and Capacity Without Energy.

Section II.B. Supplemental Control Area Services.

Section II.C. Shaping Services.

Section II.D. Reservation and Rights to Change Services.

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* In January 1997, BPA and Northwest parties executed an FPS-96 Settlement Agreement, which regards the implementation of the FPS-96 rate schedule.

A. FIRM POWER AND CAPACITY WITHOUT ENERGY

1. RATES AND BILLING FACTORS

1.1 Contract Rate

The demand charge in the Contract Rate applies to purchases of a firm capacity with no energy return product exclusively, that is, a firm power sale product. Firm capacity with energy return (Capacity Without Energy) is available under the FPS-96 rate schedule at the prices identified in section II.A.1.3. Contracts entered into on or before September 30, 1996, that refer to the demand charge in the Contract Rate section of the then applicable surplus power schedule for pricing this product will be priced under section II.A.1.3.

1.1.1 Demand Charge

The charge for demand shall be $0.87 per kilowatt per month in all months of the year, *multiplied by*
the Contract Demand unless otherwise agreed by BPA and the Purchaser.

1.1.2 Demand Charge – Capacity Without Energy Sales

See section II.A.1.3 for pricing.

1.1.3 Energy Charge

The total monthly charge for energy shall be the sum of (1) and (2):

(1) the applicable HLH rate for that month, *multiplied by*
the Purchaser's HLH Contract Energy unless otherwise agreed by BPA and the Purchaser; and

(2) the applicable LLH rate for that month, *multiplied by*
the Purchaser's LLH Contract Energy unless otherwise agreed by BPA and the Purchaser.

Applicable Months	***HLH Rate***	***LLH Rate***
September – December	49.63 mills/kWh	46.45 mills/kWh
January – March	50.39 mills/kWh	47.25 mills/kWh
April	44.74 mills/kWh	42.73 mills/kWh
May – June	24.36 mills/kWh	21.21 mills/kWh
July	29.94 mills/kWh	26.09 mills/kWh
August	42.68 mills/kWh	37.06 mills/kWh

1.2 Flexible Rate

Demand and/or energy charges may be specified at a higher or lower average rate as mutually agreed by BPA and the Purchaser. Billing factors shall be Contract Demand and Contract Energy unless otherwise agreed by BPA and the Purchaser.

1.3 Capacity Without Energy

1.3.1 Flexible Rate

For sales not covered by section II.A.1.3.2 the rate(s) for Capacity Without Energy sales shall be as mutually agreed by BPA and the Purchaser.

1.3.2 Posted Rate

The posted rates shall be applied to contracts entered into, on, or before September 30, 1996, that include Capacity Without Energy provisions where payment shall be at the demand charge associated with the Contract Rate of the then applicable surplus power rate schedule. These rates may also be applied to contracts for Capacity Without Energy entered into, on, or after June 1, 2000. For sales pursuant to such contracts the monthly charge for Capacity Without Energy shall be the applicable rate for that month, *multiplied by* the Purchaser's Contract Demand associated with the purchase of Capacity Without Energy.

Applicable Months	***Rate***
September – December	$12.20/kW-mo.
January – March	$8.95/kW-mo.
April	$8.13/kW-mo.
May – June	$6.68/kW-mo.
July	$10.78/kW-mo.
August	$16.04/kW-mo.

2. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

Adjustments, Charges, and Special Rate Provisions are described in the GRSPs. Relevant sections are identified below.

2.1 Rate Adjustments

Rate Adjustment	***Section***
Unauthorized Increase Charge	II.W.

2.2 Special Rate Provisions

Special Rate Provisions	***Section***
Cost Contributions	II.E.

B. SUPPLEMENTAL CONTROL AREA SERVICES

1. RATES AND BILLING FACTORS

The charge for Supplemental Control Area Services shall be the applicable rate(s) times the applicable billing factor(s), pursuant to the agreement between BPA and the Purchaser.

The rate(s) and billing factor(s) for Supplemental Control Area Services shall be as established by BPA or as mutually agreed by BPA and the Purchaser.

2. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

Adjustments, Charges, and Special Rate Provisions are described in the GRSPs. Relevant sections are identified below.

2.1 Rate Adjustments

Rate Adjustment	***Section***
Unauthorized Increase Charge	II.W.

2.2 Special Rate Provisions

Special Rate Provisions	***Section***
Cost Contributions	II.E.

C. SHAPING SERVICES

1. RATES AND BILLING FACTORS

The charge for Shaping Services shall be the applicable rate(s) times the applicable billing factor(s), pursuant to the agreement between BPA and the Purchaser.

The rate(s) and billing factor(s) for use of Shaping Services shall be as established by BPA or as mutually agreed by BPA and the Purchaser.

2. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

Adjustments, Charges, and Special Rate Provisions are described in the GRSPs. Relevant sections are identified below.

2.1 Rate Adjustments

Rate Adjustment	***Section***
Unauthorized Increase Charge	II.W.

2.2 Special Rate Provisions

Special Rate Provisions	***Section***
Cost Contributions	II.E.

D. RESERVATION AND RIGHTS TO CHANGE SERVICES

1. Rates and Billing Factors

The charge for Reservation and Rights to Change Services shall be the applicable rate(s) times the applicable billing factor(s), pursuant to the agreement between BPA and the Purchaser.

The rate(s) and billing factor(s) for Reservation and Rights to Change Services shall be as established by BPA or mutually agreed by BPA and the Purchaser.

2. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

There are no additional adjustments, charges, or special rate provisions for the Reservation and Rights to Change Services.

GENERAL TRANSFER AGREEMENT DELIVERY CHARGE

GENERAL TRANSFER AGREEMENT DELIVERY CHARGE

Customers who purchase Federal power that is delivered over non-Federal low voltage transmission facilities shall pay a GTA Delivery Charge. The GTA Delivery Charge is a BPA Power Business Line charge for low voltage delivery service of Federal power provided under General Transfer Agreements (GTAs) and other non-Federal transmission service agreements.

1. RATE

$0.946 per kilowatt per month

2. BILLING FACTOR

The monthly Billing Factor for the GTA Delivery rate shall be the total amount of Federal power delivered on the hour of the Monthly Transmission Peak Load at the low voltage Points of Delivery provided for in GTA and other non-Federal transmission service agreements.

At those Points of Delivery that do not have meters capable of determining the demand on the hour of the Monthly Transmission Peak Load, the Billing Factor shall equal the highest hourly demand that occurs during the billing month at the Point of Delivery multiplied by 0.79.

(*Monthly Transmission Peak Load* is the peak loading on the Federal transmission system during any hour of the designated billing month, determined by the largest hourly integrated demand produced from the sum of Federal and non-Federal generating plants in BPA's Control Area and metered flow into BPA's Control Area.)